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Xcel Energy
Docket No.: E002/CN-05-123
Response To: MN Dept of Commerce   Information Request No. 11
Date Received: August 1, 2005

Question:

Subject: CON Supplement – Renewable distributed generation (DG) alternative.

1. **Strategist Inputs.** Please provide all DG technology inputs for the Strategist model that were developed by PA Consulting (including assumed technology capital costs, operating costs, energy production, operating characteristics, capacity patterns, local load aggregations, emission rates). If possible please submit the information as a spreadsheet.

2. **DG Location.** Please provide the rationale for limiting the area of DG to within the Xcel Energy North service territory.

3. Please clarify whether the DG analysis assumes that specific industrial or commercial electric loads must be identified as the end user in order to assess the cost and feasibility of a potential DG technology. If so, please explain.

4. **Load Aggregation and DG Analysis.** To the extent not provided in requests above, please provide the complete PA Consulting analysis, including the processes, assumptions and methods used in all four steps described on page S.56. For example, please provide detailed information regarding how DG opportunities were selected and sized based on customer thermal and electrical load, and how (or whether) customers were aggregated in order to be evaluated as potential DG sites. Please also describe in detail how PA Consulting screened and narrowed the list of commercially viable DG technologies assumed for 2010 and 2013 and then matched potential technology applications to the customer or load grouping opportunities, i.e., such as by plant size, fuel restrictions, electrical and thermal load match.

5. Steam Retrofits. Presumably "steam retrofits" as used in the DG analysis refers to the addition or modification of a back-pressure or extraction turbine to co-generate electricity. However, please provide a more detailed description of "steam retrofits" as used for the DG analysis.

6. **Wind accreditation factor.** Please explain the basis for a 13.5% accreditation factor for wind.

Response:

1. File "DOC-11 Attachment 1.xls" contains the DG technology inputs for the Strategist model that were developed by PA Consulting. Tab "2010 Inputs from PA" shows the inputs used for the scenarios in which Monticello was shut down at the end of its current license. Tab "2013 Inputs from PA" shows the inputs used for the scenarios in which Monticello was shut down at the end of 2014.

   Because DG units are close to load centers, line losses are not a factor in transmission from generation to load. In the Strategist model, the energy sales forecast requirements include the transmission line losses that would be seen if we installed traditional large generation units on the system. The demand forecast that is included in Strategist is created from the energy forecast, and thus also includes a transmission line loss factor. The line loss factor that is included in the energy forecast is approximately 8.1%. The energy loss factor equates to a demand loss factor of approximately 3.4%. In the DG analysis, we included a unit in the resource mix that offsets the line losses that would otherwise have to be fulfilled by the traditional larger units. For each of the DG scenarios, the offset unit was defined to be 8.1% of the energy that the DG units produce and 3.4% of the capacity of the DG units. The offset units do not have any costs associated with them. Each of the input data sets include a line titled "Offset Unit" that shows the capacity and energy values associated with that scenario.

   The fuel prices used in Strategist for each of the DG units are listed in the tab "Fuel Strategist". The file also includes two tabs that show the supply curves for the renewable and non-renewable DG units.

2. The most commonly used definitions of Distributed Generation include the concept that distributed generation refers to small, power generating resources located near the end user on the distribution system. Since Monticello serves Xcel Energy North customers we assumed Distributed Generation to replace it would also have to directly offset electricity consumption of Xcel Energy North customers.

3. The DG analysis looked at current Xcel Energy customer data to determine the availability of various types and sizes of DG to fit that particular data. While it is also possible to consider aggregation of multiple customers for a

single DG application, PA did not perform this type of analysis.

4. Attached is a copy of PA Consulting Group's final report detailing its study method and results. DG technology screening and commercial viability are discussed in section 2 and the further technology matches are addressed in section 3.

5. See PA Consulting Group's final report, section 3.3.

6. As stated in our response to Information Request DOC-49 in Docket E002/RP-04-1752:
MAPP accreditation
In the last several years, Xcel Energy has used MAPP accreditation values for wind of 10 percent and 13.5 percent based on actual performance data. For this Plan, Xcel Energy chose to use the higher value of 13.5 percent because current MAPP accreditation information supports this value. Xcel Energy has several wind purchases that are accredited with MAPP on a before-the-fact basis. The accreditation values for the peak month (July) range from 7.5 to 13.6 percent. We chose to accredit the wind in the Strategist model at the high end of the range, and simplified the number to 13.5 percent. The accreditation for the peak month of each purchase is listed in the table below.

2003 - 2004 MAPP Accreditation for Wind Before-the-Fact Accreditation Month of July			
	Nameplate Capacity MW	Accredited Capacity MW	Accredited Capacity % of Nameplate
Buffalo Ridge Phase I	25	1.865	7.5
Buffalo Ridge Phase II	107.25	10.865	10.1
Buffalo Ridge Phase III	103.5	13.105	12.7
Lakota	11.25	1.535	13.6
Shaokatan	11.88	1.58	13.3
Woodstock	10.2	1.11	10.9

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Docket No. E002/CN-05-123
Attachment to DOC-11

PA Consulting Group

Xcel Energy

Distributed Generation as an Alternative to the Monticello Generating Station

August 5, 2005

PA

Xcel Energy

Distributed Generation as an Alternative to the Monticello Generating Station

August 5, 2005

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TABLE OF CONTENTS

1. INTRODUCTION AND SUMMARY

1.1 BACKGROUND

Xcel Energy's (Xcel or the Company) Monticello Nuclear Generating Station is licensed by the NRC to operate until 2010. Xcel is currently attempting to relicense this facility for an additional 20 years. In order to continue to operate Monticello beyond 2010, Xcel will require additional storage space for spent nuclear fuel. In January 2005, Xcel filed a Certificate of Need Application with the Minnesota Public Utilities Commission (PUC) for an Independent Spent Fuel Storage Installation (ISFSI) at Monticello.

As part of the Certificate of Need process, the Minnesota PUC will consider alternatives to the ISFSI, including alternatives that would shut down the Monticello Nuclear Generating Station. The Company submitted a number of alternatives with its application. In reviewing the completeness of its application, the PUC determined that the Company should also submit an alternative that would replace Monticello with a combination of demand-side management and Distributed Generation (DG). Xcel asked PA Consulting Group (PA) to conduct a study of DG alternatives. This report describes the study and its results.

1.2 DEFINITION OF DISTRIBUTED GENERATION

For purposes of this study, the working definition of distributed generation is *generation with a capacity between 100 kW and 10 MW located within the electric distribution system at or near the end user.*

Other definitions of DG from well-known organizations include:

- ***Underwriter Laboratories:*** "Distributed Generation (DG) is the implementation of various power generating resources, near the site of need, either for reducing reliance on, or for feeding power directly into the grid."[1]
- ***California Energy Commission:*** "Distributed energy resources (DER) are parallel and stand-alone electric generation units located within the electric distribution system at or near the end user."[2]
- ***U.S. DOE:*** "Distributed generation – small, modular electricity generators sited close to the customer load – can enable utilities to defer or eliminate costly investments in transmission and distribution (T&D) system upgrades and provide customers with better quality, more reliable energy supplies and a cleaner environment."[3]

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[1] http://www.ul.com/dge/.

[2] http://www.energy.ca.gov/distgen/.

[3] http://www.eere.energy.gov/EE/power_distributed_generation.html.

- ***Consumer Energy Council of America:*** "Distributed generation is a system composed of generation located near the energy consumer's site that may be highly integrated with the electric grid to provide multiple benefits on both sides of the utility meter."[4]

- ***Oregon Public Utility Commission:*** "Distributed generation produces electricity at or near the place where it is used."[5]

1.3 OBJECTIVE AND SCOPE OF STUDY

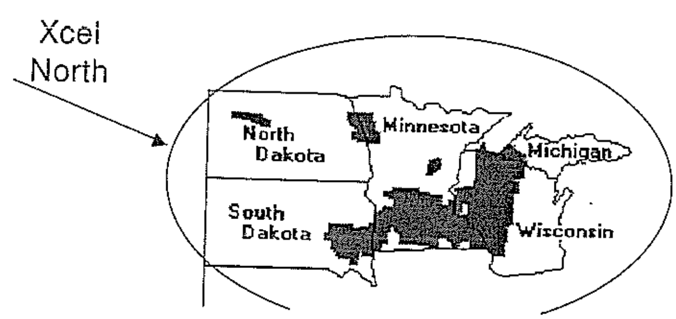
The objective of the study was to identify the DG technology or technologies that could be installed in the Xcel North service territory, as shown in Figure 1-1, and are most likely to be able to cost-effectively replace 579 MW of capacity associated with baseload type energy (85% capacity factor or greater). Xcel requested that PA examine DG's potential under two scenarios:

- ***Immediate shutdown.*** The DG capacity would need to be on-line to replace Monticello as of a plant shut down on May 1, 2010.

- ***Deferral with peaking.*** Xcel Energy would construct combustion turbines to bridge a gap until the DG capacity could be implemented no later than May 1, 2013.

Xcel also requested that for each period, in addition to a least-cost portfolio of technologies, that PA identify a least-cost renewable portfolio.

Figure 1-1
Xcel North Service Territory



[4] http://www.cecarf.org/Programs/DG/DGFacts.html.

[5] Oregon Public Utility Commission. "Distributed Generation in Oregon: Overview, Regulatory Barriers and Recommendations." February 2005.

For each portfolio, Xcel requested a set of DG technology inputs for their utility planning model, Strategist. These inputs consisted of initial capital costs, annual operating costs, annual energy production, seasonal capacity patterns and emission rates. Xcel also asked that PA consider that the technologies be "community-based." However, following discussions with Xcel it was unclear as to the precise meaning of the phrase "community-based" and, importantly, how it would be applied to this study. Consequently, PA did not include consideration of this concept in the analysis.

1.4 STUDY ASSUMPTIONS

The following assumptions are integral to the analysis.

1.4.1 DG ownership

PA assumed that Xcel, as opposed to the customer, would install, own and maintain the equipment. The costs associated with the technologies represent the total capital costs and the fixed and variable operating costs.

1.4.2 Avoided T&D costs

DG technologies can have additional value if they allow a utility to avoid expenditures on transmission and/or distribution (T&D). Xcel believes based on its previous study of this issue that there is little or no opportunity for such T&D cost avoidance. Consequently, PA did not consider avoided T&D costs in its analysis.

1.4.3 Emission costs

PA identified the emission rates associated with each technology and included the emission rates in the planning model inputs provided to Xcel. While PA included the capital cost associated with current and anticipated emissions reduction technology, PA did not include the costs associated with emission allowances in our cost screening, as that is being addressed in Xcel's system-wide modeling.

1.4.4 Size of DG units

PA assumed that DG systems would be sized in proportion to the customers' site needs, in terms of electricity and (for combined heat and power [CHP]) thermal load. PA assumed the sizes would be restricted to the 10 kW to 10 MW range.

1.4.5 T&D losses

Projected DG installations are assumed to occur at the Company's distribution level. Line losses, therefore, were not an element of consideration for PA.

1.4.6 Capacity factors

PA assumed all dispatchable fossil-fuel DG technologies would operate at an 85% capacity factor, consistent with base load generation. Biomass-based DG technologies were assumed to have an 80% load factor.[6] Non-dispatchable technologies, i.e., wind, were assumed to operate as much as possible (which translated into a 20% load factor, consistent with a class 3 wind environment found in most of the southeastern state of Minnesota, and a capacity credit contribution of 13.5% of total wind capacity).

1.5 OVERVIEW OF APPROACH

The analysis involved the following steps:

- technology identification, characterization, screening
- target area profiling
- DG technology and customer application matching
- development of recommended portfolios.

1.5.1 Technology identification, characterization, screening

PA identified a broad slate of DG technologies including: low head hydro, geothermal, solar, concentrated solar, wind, reciprocating engines, combustion turbines, Stirling engines, fuel cells (four types), microturbines, steam turbines and landfill gas applications. PA then narrowed the list of potential technologies, as described in Section 2.1, to those that were deemed reasonably commercially viable within Xcel's service territory by May 1, 2010 or May 1, 2013. For each of these viable technologies, PA compiled data on capital costs, operating costs and operating characteristics.

1.5.2 Target area profiling

PA solicited data from Xcel to allow it to identify, by SIC code, aggregate customer site and load information. PA parsed the customer data into five major load categories (i.e., 100 kW to 500 kW; 501 kW to 1,000 kW; 1,001 kW to 2,500 kW; 2,501 kW to 5,000 kW; and 5,001 kW to 10,000 kW) by customer application.

1.5.3 DG technology and customer application matching

PA proceeded to match potential DG applications to customer applications (CHP or power only) and load groupings. PA then calculated a levelized cost for each relevant technology application to a customer grouping. The result of this process was a list of feasible technologies and applications, each with a calculated levelized energy cost.

1.5.4 Develop recommended portfolios

Using the customer data and the technology data, PA then constructed two recommended portfolios for each of the respective study periods (i.e., 2010 and 2013). For each period, one portfolio consists of the least-cost options, regardless of fuel type, the other consists of the least-cost renewable options. The cost criterion for selection was the levelized energy cost

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[6] From Power Technologies 2003 Data Book, by the National Renewable Energy Laboratory (NREL), in Exhibit 12.1 (titled Renewable Energy Impacts Calculation). Web reference: http://analysis.nrel.gov/databook/tables.asp?chapter=8&table=43.

which factored in the cost and technical performance factors of each viable DG technology according to the size, type, on-site thermal and electricity needs of each DG application.

1.6 RESULTS

The amount of capacity represented by technology type and size (e.g., steam turbine retrofits in the 5.0 – 10.0 MW range, or wind turbines in the 2.5 to 5.0 MW range) in each of set of portfolios (both Least Cost and Renewable) reflects the cost characteristics of the technology and the load characteristics of the customers. That is, in each size category, as much capacity of the relevant technology was added as analysis suggested that annual customer energy usage – as opposed to peak demand – in that category would support.

For example, the least-cost technology in both 2010 and 2013 is steam turbine retrofits of 5 to 10 MW in capacity. The suggested amount of capacity to be added in that category (i.e., 3.5 MW) reflects both customer load factor – or annual energy use - and the limited number of sites in the service territory in which excess steam is available to be converted to electricity using an appropriately sized retrofit. Similar logic applies in the other Least-Cost portfolio categories.

In terms of the Renewable portfolios, the same logic was applied. Customer type and demand characteristics were examined to identify which technologies or combination of technologies (e.g., wind, micro-turbine/biomass) to use, and the size of the installation where appropriate given the customer profile. In each case, as much as possible of the cheapest renewable technology was applied. It should also be noted that in the case of wind, the capacity accreditation column shown in Table 1-2, below, represents the portion of the total amount of installed wind capacity that is "accredited" for planning purposes. The analysis assumed an accreditation factor of 13.5%. For example, in the case of the 2010 Renewable portfolio, 0.5 MW of wind in the 2.5 to 5.0 MW range are accredited, which would represent a nameplate installation of 3.6 MW (3.6 MW x 13.5% = 0.5 MW). Also, as previously noted, the analysis assumed installations at or near the load, replacing existing customer supply. Consequently, it did not assume any new, large-scale wind farms located remote from load centers.

1.6.1 Least-cost portfolio

The Least-Cost portfolios in both 2010 and 2013 consist entirely of natural gas-fired technologies, including steam turbines retrofit to existing industrial processes, and reciprocating engines. The levelized cost for these technologies is between 4.6 and 5.7 cents/kilowatt hour (kWh) in 2010, with slightly lower prices in 2013 due to anticipated technological improvements, lower capital costs and lower fuel costs. Table 1-1 summarizes the technologies that provide the least-cost 579 MW of capacity.[7]

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[7] In both periods, the total amount of DG proposed to be added is in excess of the needed 579 MW. That is because the DG applications are added in "blocks" of capacity as opposed to single megawatts.

Table 1-1
Least-Cost Portfolio

DG Technology	Application	DG Site Size (MW)	Fuel	Levelized Energy Cost (2004$/kWh)	Accredited Capacity (MW)
2010					
Steam Turbines/Retro	CHP	5.0-10.0	Natural Gas	0.046	3.5
Steam Turbines/Retro	CHP	2.5-5.0	Natural Gas	0.047	1.5
Reciprocating Engines	CHP	5.0-10.0	Natural Gas	0.051	128.3
Steam Turbines/Retro	CHP	1.0-2.5	Natural Gas	0.052	5.0
Reciprocating Engines	CHP	2.5-5.0	Natural Gas	0.053	116.2
Reciprocating Engines	CHP	1.0-2.5	Natural Gas	0.054	94.5
Reciprocating Engines	CHP	0.5-1.0	Natural Gas	0.056	228.1
Reciprocating Engines	CHP	0.1-0.5	Natural Gas	0.057	119.4
					696.6
2013					
Steam Turbines/Retro	CHP	5.0-10.0	Natural Gas	0.045	3.6
Steam Turbines/Retro	CHP	2.5-5.0	Natural Gas	0.046	1.6
Reciprocating Engines	CHP	5.0-10.0	Natural Gas	0.048	145.4
Reciprocating Engines	CHP	2.5-5.0	Natural Gas	0.050	129.1
Steam Turbines/Retro	CHP	1.0-2.5	Natural Gas	0.050	5.3
Reciprocating Engines	CHP	1.0-2.5	Natural Gas	0.051	105.1
Reciprocating Engines	CHP	0.5-1.0	Natural Gas	0.052	251.8
					641.8

1.6.2 Renewable portfolio

PA was not able to identify sufficient renewable DG technologies to offset Monticello's capacity. As shown in Table 1-2, PA identified renewable DG totaling only 21 MW in 2010 and 38 MW in 2013 that met our criteria. As with the Least-Cost portfolio, the Renewable portfolio reflects customer site characteristics. Wind turbines are the least cost technology, but they are limited to sites with available land, a reasonable amount of wind, load matching the generation capacity.

Table 1-2
Renewables Portfolio

DG Technology	Application	DG Site Size (MW)	Fuel	Levelized Energy Cost (2004$/kWh)	Accredited Capacity (MW)
2010					
Wind Turbines	Power Only	2.5-5.0	Wind	0.068	0.5
Steam Turbines/New	Power Only	2.5-5.0	Biomass (wood waste)	0.070	3.9
Wind Turbines	Power Only	1.0-2.5	Wind	0.077	1.1
MT/Biogasifiers	Power Only	0.1-0.5	Biomass (ag waste)	0.082	10.6
Wind Turbines	Power Only	0.5-1.0	Wind	0.086	1.5
Wind Turbines	Power Only	0.1-0.5	Wind	0.105	3.0
					20.6
2013					
Wind Turbines	Power Only	2.5-5.0	Wind	0.065	0.5
Steam Turbines/New	Power Only	2.5-5.0	Biomass (wood waste)	0.070	4.1
MT/Biogasifiers	Power Only	1.0-2.5	Biomass (ag waste)	0.070	7.0
MT/Biogasifiers	Power Only	0.5-1.0	Biomass (ag waste)	0.071	8.3
Wind Turbines	Power Only	1.0-2.5	Wind	0.073	1.11
MT/Biogasifiers	Power Only	0.1-0.5	Biomass (ag waste)	0.075	11.1
Wind Turbines	Power Only	0.5-1.0	Wind	0.080	1.6
Wind Turbines	Power Only	0.1-0.5	Wind	0.098	3.1
					36.8

2. DG TECHNOLOGY CHARACTERIZATION

This chapter describes the general study process employed by PA to select particular DG technologies for detailed consideration, and how those technologies were characterized. In sum, PA first identified potential technologies, compiled a list of relevant cost and performance factors, then estimated the cost of fuel to drive the technologies. Using those inputs, PA then estimated levelized energy costs.

2.1 SLATE OF TECHNOLOGIES CONSIDERED

PA identified a broad slate of potential DG technologies, renewable fuels and applications that merited at least initial consideration in the study, including: low head hydro, geothermal, solar, concentrated solar, wind, reciprocating engines, combustion turbines, Stirling engines, fuel cells (four types), microturbines, steam turbines and landfill gas applications. A description of technologies is provided in Appendix A.

PA narrowed the list of technologies to those that were deemed reasonably commercially viable within Xcel's service territory. The elimination criteria included fuel availability, capacity (i.e., sized between 100 kW to 10 MW), and/or commercial maturity (i.e., cost and production capability). For example, particular technologies (e.g., 0.1 – 0.5 MW combustion turbines and 5-10 MW microturbines) were eliminated because PA believes that they are unlikely to become commercially viable in the target timeframe. The result was a qualified list of technologies, fuels and applications that are, or are likely to be, viable for installation by Xcel in 2010 or 2013. Table 3-1 provides a summary of the considerations.

Table 2-1
Viability Considerations

Technologies:	Considerations	Evaluated *
Reciprocating engines	Mature and commercially viable	✓
Combustion turbines	Mature and commercially viable	✓
Steam turbines	Mature and commercially viable	✓
Photovoltaic cells	High cost. and lack of solar concentration	
Concentrated solar	High cost and lack of solar concentration	
Micro turbines	Mature and commercially viable	✓
Stirling engines	Below minimum size	
Fuel cells	Maturing toward economic viability	✓
Renewable Fuels:		
Geothermal	Insufficient natural resource	
Landfill gas	Insufficient incremental resource base	
Biodiesel	Maturing	✓
Biomass	Agricultural waste and wood based	✓
Low-head hydro	Insufficient incremental resource base	
Wind	Maturing toward economic viability	✓
Applications:		
Combined heat & power	Mature and commercially viable	✓

* "Evaluated" refers to whether levelized energy cost analytics were performed.

2.2 TECHNOLOGY COST AND PERFORMANCE FACTORS

To estimate the levelized cost for each technology and thereby identify the least cost technology combinations, estimates of the following factors were developed/identified:

1. capital cost
2. O&M cost
3. appropriate fuel type
4. heat rate (heat input divided by electricity output
5. electricity-to-thermal (E/T) energy output ratio for CHP applications.

For capital and O&M costs, PA extrapolated Department of Energy (DOE) data and forecasts to arrive at costs for both 2010 and 2013.[8] These costs were in turn adjusted to reflect 2004 real dollars, as were all values, to make them compatible with other inputs in Xcel's Strategist capacity planning model. Detailed tables showing the performance characteristics are presented in Appendix B.

2.3 FUEL PRICE CHARACTERIZATION

To estimate fuel costs, PA performed the following for each noted fuel type:

- ***natural gas*** – combined Xcel's May 2005 wholesale natural gas price forecast with a transport adjustment, also provided by Xcel, and adjusted to 2004 dollars

- ***diesel (#2 oil)*** – combined Xcel's latest wholesale #2 diesel price forecast with a transport and distribution adjustment, also provided by Xcel, and adjusted to 2004 dollars

- ***biodiesel*** – calculated the average price differential between Midwest #2 diesel and biodiesel[9] (found to be 2.4% from 2002 to 2005) and applied to the all-in diesel (#2 oil) fuel price

- ***agricultural waste*** – PA estimated an on-site cost for 2005, escalating at 1% per year in real terms, based on:

  - assumed agricultural waste prices for agricultural crop residues (e.g., wheat straw and corn stover) and so-called energy crops (such as hybrid poplar, hybrid willow and switchgrass)

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[8] "Gas Fired Distributed Energy Resource Technology Characterizations," Gas Research Institute (GRI) and National Renewable Energy Laboratory (NREL) – US Department of Energy, November 2003; "Power Technologies Data Book," National Renewable Energy Laboratory (NREL) – US Department of Energy, 2003 Edition.

[9] Differential derived by PA based on data reported in the Alternative Fuels Price Report from April to March 2002 to 2005 (US Department of Energy, Energy Efficiency and Renewable Energy), http://www.eere.energy.gov/afdc/resources/pricereport/price_report.html.

- agricultural waste prices averaging $19 ($2004) per dry ton – equivalent to $1.10 per mmBtu)[10]

- transportation costs averaging $0.91 per mmBtu ($2004) for distances of less than 50 miles and relatively small size loads, given the size of the gasifier applications being considered.[11]

The result is a delivered agricultural waste price of $2.00/mmBtu for 2005 ($2004) equivalent to $34.5/dry ton. This estimate is consistent with the range of delivered prices estimated by Oak Ridge National Laboratory.[12]

- ***wood waste*** – PA used an estimate of $10/wet ton equivalent to $18.5/dry ton, based on a 54% wet/dry factor.[13] This is consistent with a $1.07/mmBtu ($2004) price for sawmill residues.[14]

For use in steam turbine DG applications, PA assumed a 50/50 mix of wood waste and wood fuel. The cost of wood fuel was estimated at $45 per dry ton to reflect a potential range between $40/ton and $50/ton. The result is a weighted fuel cost of $1.78/mmBtu or the equivalent of $31.8/dry ton for the composite fuel feedstock. PA added to that commodity cost an average current transportation cost of $0.91/mmBtu for distances of less than 50 miles. The result is a delivered price of $2.70/mmBtu ($2004) for steam-turbine-based DG applications. PA also factored potential projected increases in transportation costs (labor and fuel).

Appendix C provides price forecasts of natural gas and #2 oil.

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[10] Ratio referenced in DOE's study: "Biomass for Electricity Generation" by Zia Haq. Work done by EIA as part of its National Energy Modeling System (NEMS) analyses. Web reference: http://www.eia.doe.gov/oiaf/analysispaper/biomass/index.html.

[11] Ibid. The EIA's data used in DOE's NEMS studies show transportation costs for switchgrass – the most likely agricultural waste component – up to $0.87/mmBtu in $2002. We selected the high end estimate to reflect the small quantities needed by the small gasifiers (less than 750 kW)

[12] Oak Ridge National Laboratories. *A National Assessment of Promising Areas for Switchgrass, Hybrid Poplar or Willow Energy Crop.* ORNL-6944. Web ref: http://bioenergy.ornl.gov/reports/graham/lakestates.html.

[13] DOE's study: "Biomass for Electricity Generation" by Zia Haq. Work done by EIA as part of its National Energy Modeling System (NEMS) analyses. Web reference: http://www.eia.doe.gov/oiaf/analysispaper/biomass/index.html.

[14] A study by the Washington State University Cooperative Extension Energy Program showed an average of $2.5/mmBtu for the price of small wood waste residues used in commercial space heating applications. Web reference: http://www.energy.wsu.edu/ftp-ep/pubs/renewables.

3. DEVELOPMENT OF RECOMMENDED PORTFOLIOS

This chapter describes how PA developed the recommended portfolios for both least cost and least-cost renewable-based DG installations in Xcel's North service area. Whenever appropriate, PA considered both power-only and CHP DG applications.

PA's focus was on DG applications related to customer sites with peak loads greater than 100 kW but less than 10,000 kW. To characterize that target customer base, PA based its analysis on a customer segmentation matrix provided by Xcel.

The analysis is, in large part, statistical in nature, since PA relied on the statistical customer consumption and load factor profile provided by Xcel. PA did not address other customer or site-specific data, both of which can affect the size of the actual DG potential, as discussed at the end of this chapter.

The remainder of the chapter describes how PA:

- characterized the target customer base
- calculated Levelized Energy Costs (LECs)
- estimated the potential for fossil-fuel DG (power-only and CHP)
- estimated the potential for renewable-based DG
- developed the recommended portfolios.

3.1 TARGET CUSTOMER BASE

The Xcel target customer base was segmented by site peak demand, in five peak demand size categories:

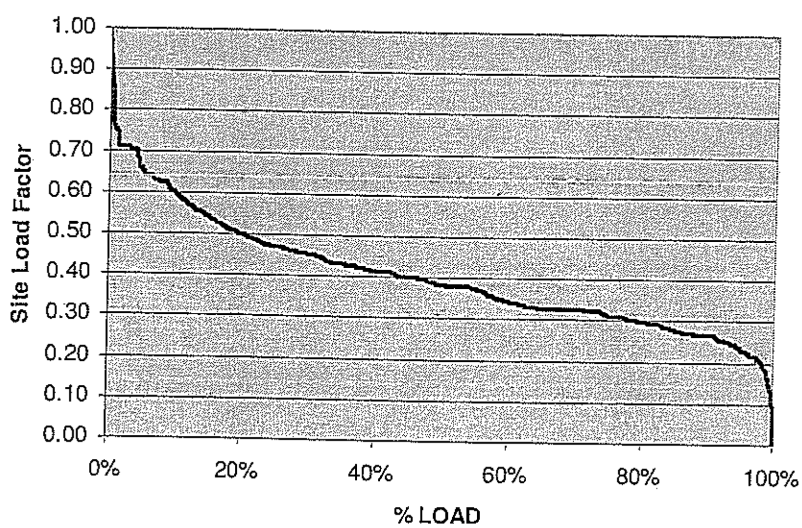
- between 100 and 500 kW
- between 501 kW and 1,000 kW
- between 1,0001 kW and 2,500 kW
- between 2,501 kW and 5,000 kW
- between 5,0001 kW and 10,000 kW.

These customer base size categories were chosen consistent with the categorization of the various DG technologies' technical and cost performance characteristics, previously described.

The customer data showed a total of 11,965 sites with an annual consumption of 16,458 GWh for the 100-10,000 kW customer peak range, broken down as shown in Table 3-1. The overall load factor for the entire customer population on sites with peak load below 10 MW is 36.7%. The load factor distribution curve is shown in Figure 3-1.

Table 3-1 Target Customer Base			
Customer Peak Range (kW)	Number of Sites	Annual Consumption (GWh)	% of Total Power Consumption
100-500	9,851	6,411	39.0
501-1,000	1,300	3,371	16.2
1,001-2,500	511	2,668	12.2
2,501-5,000	201	2,001	12.2
5,001-10,000	102	2,008	20.5
Total (5 classes)	11,965	16,458	100.0

Figure 3-1
Load Factor Distribution Curve for Target Customer Base



The target customer base information was further segmented by standard industrial classification (SIC) code.[15] The SIC codes were used to allow for targeting of DG applications to customer segments. This segmentation included agricultural, manufacturing, commercial and institutional applications.[16]

3.2 CALCULATION OF LEVELIZED ENERGY COST

Cost screening provided a basis for selecting the most cost-effective technologies from among the possible combinations of DG technologies, application size, customer application, and fuel used. The economics of each commercially viable combination were evaluated for each technology combination (technology, application, size and fuel). In total PA assessed the levelized energy cost of 90 technology combinations. Considerations in these combinations include:

- ***technologies*** – reciprocating engines, combustion turbines, microturbines, microturbines with gasifiers, fuel cells (multiple individual types), wind turbines and steam turbines
- ***applications*** – power only or in CHP
- ***size*** – five distinct size ranges between 100 kW and 10 MW
- ***fuels*** – natural gas, fuel oil (#2 diesel), biodiesel, agricultural waste and wood waste

PA calculated LECs based on the formula below:

Levelized Energy Cost = Levelized Capital Cost (LCC)/(total electricity generated)

Where:

LCC = Capital Cost * Capital Cost Recovery (CCR) factor + Annual O&M + Fuel Cost

$CCR = r/(1-(1+r)^{-n})$

and where:

r = Xcel's Weighted Average Cost of Capital (WACC), which is 7.26%
n = asset life (20 years)

LEC represents the entire cost of ownership across the life of an asset, including capital expenditures, operations and maintenance, and fuel on a per unit of generation basis. In other words, it represents the time-weighted average cost to produce electricity over the projected life of the asset.

The technologies, performance factors and LEC results are presented in Appendix B.

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[15] Using the 1987 SIC code classification, which is the customer classification used by Xcel.

[16] One SIC code (99) reflected unspecified business activities (with 2,209 sites and about 16% of the total target consumption load).

3.3 TECHNICAL POTENTIAL FOR FOSSIL-FUEL DG APPLICATIONS

PA assessed the potential of both power only and CHP applications.

3.3.1 Power-only fossil fuel applications

To assess the technical potential for fossil fuel-based power-only DG applications, PA proceeded in two steps. First, PA characterized the equivalent baseloaded power-only DG capacity that could be installed in each SIC code/size application segment (e.g., SIC 2653 and peak load between 1,001 kW and 2,500 kW). To do so, PA divided the annual consumption in each SIC code/size segment by the number of hours in the year (8,760) and expressed the result in MW of equivalent baseload DG capacity that, if it were installed on all the sites that make up that segment, would deliver the same amount of electricity over the year.

Next, PA screened the target customer universe to select those power-only DG applications with a high load factor since a high load factor increases the cost-efficiency of the DG installation (i.e., a greater load factor means more energy generated, which means a greater base of kWh over which to spread the costs). To that end, PA developed a load factor distribution curve for the entire target universe and determined that applications with load factors at 46% or above would yield a technical DG potential of approximately 600 MW by 2010.[17] PA used that threshold to characterize the target technical potential for DG-only power applications.

The result was a total power-only DG technical potential of 602 MW for 2010, segmented as shown in Table 3-2.

Table 3-2
Power-Only DG Technical Potential (2010)

Customer Peak Range (kW)	Number of Sites	DG Capacity (MW)	% of Total Power-Only Potential
100-500	878	113	18.8
501-1,000	525	218	36.2
1,001-2,500	178	149	24.8
2,501-5,000	31	60	10.0
5,001-10,000	14	61	10.1
Total (5 classes)	1,626	602	100.0

[17] Per Xcel data, PA assumed load increased by 10% by the year 2010. PA assumed a 5% increase between 2010 and 2013.

3.3.2 CHP fossil-fuel applications

To assess the technical potential for fossil fuel-based CHP DG applications required four steps.

First, PA screened the SIC code applications which have historically proven to be CHP-friendly. Although all manufacturing SIC codes were retained in that first step, several commercial or institutional applications were screened out. This allowed for focus on SIC applications with better potential such as hospitals, universities, educational institutions, nursing homes, shopping malls, large retail stores and office buildings.[18]

The result was a CHP target subset market that accounted for an annual consumption of 8,126 GWh or about half of the total power consumption in the original customer target universe.

The power load associated with potential CHP DG sites was also more evenly distributed, as shown in Table 3-3.

Table 3-3
Current CHP DG Target Subset Market

Customer Peak Range (kW)	Number of Sites	Annual Consumption (GWh)	% of Total Power Consumption
100-500	3,152	2,293	28.2
501-1,000	747	2,071	25.5
1,001-2,500	271	1,408	17.3
2,501-5,000	116	1,145	14.1
5,001-10,000	58	1,209	14.9
Total (5 classes)	4,344	8,126	100.0

Second, PA estimated the technical potential for the amount of CHP DG capacity that could be installed in the target subset market, assuming that all these applications are sized to meet the on-site base thermal load. To estimate the base thermal load in each CHP SIC-size segment, PA divided the estimated power-only base load capacity of that segment by the segment's estimated E/T ratio. Essentially, the application of an E/T ratio to a segment's

[18] See for example the May 2003 report by Energy & Environmental Analysis (EEA) titled *Market Potential for Advanced Thermally Activated BCHP in Five National Account Sectors*; prepared for Oak Ridge National Laboratory. That report provides useful assessments regarding best CHP applications in buildings. We also consulted the On-Site-Sycom January 2000 report tiled *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector*, prepared for the US DOE's Energy Information Administration.

electric energy use results in an amount of energy from that segment that one might reasonably conclude could be associated with or dedicated to thermal usage.

Using E/T ratios to estimate the size of CHP market potentials is a typical practice used in many market assessments conducted for the DOE, national laboratories (e.g., NREL), regional or state energy offices (e.g., Pacific Northwest region), or utilities.

Estimates of E/T ratios were assigned for each SIC code (as applicable) based on various data sources. First, for industrial manufacturing SIC codes, PA relied in large part on data from a major US DOE effort conducted by the Drexel University, titled "Energy Analysis of 108 Industrial Processes."[19] Second, for some industrial SICs and processes, PA relied on complementary information from two reports prepared for the DOE.[20]

PA also used E/T ratio data from a study conducted by Energy International Inc and Energy & Environmental Analysis Inc.[21] That study included E/T ratios for both industrial and major types of commercial and institutional (C&I) applications. Finally, PA supplemented and adjusted these various data points, as needed, based on its own DG market assessment experience.

The result was an estimate of 809 MW thermal (MWth) of current potential DG CHP capacity that could be installed if all these CHP systems were all sized to meet estimated on-site thermal energy baseload needs, as shown in Table 3-4.

Table 3-4
Potential
Thermal Baseload Capacity

Customer Peak Range (kW)	Capacity (MWth)
100-500	151
501-1,000	236
1,001-2,500	153
2,501-5,000	110
5,001-10,000	159
Total (5 classes)	809

[19] Drexel University. US DOE contract E(11-1)2862.

[20] *Opportunities for Micropower and Fuel Cell/Gas Turbine Hybrid Systems in Industrial Applications*, Subcontract 85X-TA009V. January 2000; and *Assessment of On-Site Power Opportunities in the Industrial Sector*, Contract No. 85X-TA008V, prepared by Onsite Energy Corporation, March 2001.

[21] *Technical Market Potential for CHP in the Pacific Northwest.* Energy International report No. 02-1101-BR0023.

Third, PA estimated the share of the potential thermal load that technically could be served by the five candidate CHP DG technologies, including:

- steam turbine retrofit (ST-retro) technology: essentially, applying a steam turbine to the back end of an existing boiler(s) that is already producing steam), and which is characterized by a low E/T ratio (~ 0.1)
- other non ST-retro technologies include reciprocating engines, gas turbines, microturbines and fuel cells, with high E/T ratios (0.55 and above and up to 2.05 for fuel cells).

PA estimated the potential for ST-retro DG technology by screening for CHP applications that met three tests designed to point to potentially attractive ST-retro installations:

- the application's baseload power needs were the equivalent of at least 500 kW of baseload capacity, since ST-retro applications in sizes below 500 KW do not generally make economic sense
- the application's E/T ratio was below 1 (i.e., low enough that it could efficiently accommodate the low E/T ratio of a ST-retro technology
- the application's load factors were 30% or higher (to ensure sufficient use).

Based on the approach, as described, the result was a limited ST-retro potential of 100 MWth across the customer base. Given the low E/T ratio (0.1) of ST-retro technologies, this results in ST-retro electric potential of only 10 MW, as shown in Table 3-5.

Table 3-5
ST-retro CHP DG Potential in 2010

Customer Peak Range (kW)	ST-Retro Potential Capacity (MW)
100-500	NA
501-1,000	NA
1,001-2,500	5.0
2,501-5,000	1.5
5,001-10,000	3.5
Total (5 classes)	10.0

Finally, PA estimated the share of the remaining (non-ST-retro) DG CHP potential that could be served by all four remaining DG technology options: reciprocating engines, gas turbines, micro-turbines and fuel cells. To do so, PA assumed that all these systems would be sized to meet the site's baseload thermal load, provided that the installed capacity did not exceed

80% of the sites' estimated peak load.[22] This way, all the CHP systems were reasonably sized (in proportion to the site's needs).

The resulting CHP potential in 2010 is presented in Table 3-6.

Table 3-6
CHP DG Potential (2010) By CHP Technology

Customer Peak Range (kW)	Potential Thermal Capacity (MWth)	Potential Recip Capacity (MW)	Potential Gas Turbine Capacity (MW)	Potential Microturbine Capacity (MW)	Potential Fuel Cell Capacity (MW)
100-500	157	119	NA	201	267
501-1,000	260	228	148	312	441
1,001-2,500	85	95	53	102	170
2,501-5,000	98	116	67	NA	195
5,001-10,000	105	128	88	NA	NA
Total (5 classes)	705	686	356	480	1,073

The same approach was used to characterize the 2013 DG CHP technical potential, using a 5% load-growth factor between 2010 and 2013.

3.4 TECHNICAL POTENTIAL FOR RENEWABLE-BASED DG APPLICATIONS

As shown in Table 2-1, PA focused our analysis on two potential renewable technology applications[23]:

- wind
- biomass-based applications on farms and in the wood industry

In the case of wind, PA focused on farm applications. This included crop-producing farms (producing wheat, corn and soybeans); vegetable farms; beef cattle farms; dairy farms; and forest nurseries. Customer stratification resulted in 147 sites in the relevant peak load range, but with a combined current annual load of only 79 GWh.

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[22] In other words, we calculated, for each SIC code/size segment, the CHP DG potential in that segment as the minimum of a) the segment's thermal baseload sized capacity, or b) 80% of the segment peak load.

[23] We also considered landfill gas recovery applications but we could not identify incremental candidate sites available (there are currently five sites equipped with such systems in Xcel's service area with approximately 25 MW of installed capacity).

Next, PA estimated the DG capacity potential associated with the deployment of wind turbines on each farm site, assuming that each wind turbine was sized to meet the farm's peak load.[24]

PA developed a size distribution of peak load requirements across the sites by estimating the peak load requirement for each farm segment. This gave us a wind turbine potential estimate of 44.7 MW for sites with peak loads between 100 KW and 10 MW, as shown in Table 3-7 for 2010.

Table 3-7
Estimated Farm-Based Wind Turbine Potential (2010)

Customer Peak Range (kW)	Number of Sites	Estimated Peak Capacity (MW)
100-500	123	21.9
501-1,000	17	11.4
1,001-2,500	6	7.9
2,501-5,000	1	3.6
5,001-10,000	0	0.0
Total (5 classes)	147	44.7

PA then estimated the technical potential for biomass-based applications on both farms and in the wood industry. The data indicated 127 wood industry sites with a total annual load of 179 GWh. This analysis covered both the lower and higher ends of the customer peak load size spectrum:

- on the lower end, PA estimated the potential for microturbine (MT)/gasifier-based systems up to 750 kW fueled by small gasifiers to serve applications with peak loads up to 2.5 MW. The gasifiers would use agriculture waste.
- on the higher end, PA projected the potential for steam-turbine boiler-based systems in larger wood industry applications (with peak loads above 2.5 MW). The boilers were assumed to burn wood waste from the site itself or from nearby feedstock locations.

In both cases, the applications were considered as power-only DG applications.[25] For the purpose of this analysis, PA assumed all the systems were sized to meet the on-site baseload power need.

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[24] These wind turbines are assumed to operate in a Class 3 wind environment. Web reference: www.nrel.gov/winds/pdfs/r1_1minneapolis.pdf

[25] This way, we avoided double counting with our estimates of the CHP DG potential.

The results of the analysis indicated total biomass-based DG potential for 2010 estimated at 29.2 MW, as shown in Table 3-8:.

Table 3-8 Estimated Biomass-Based DG Technical Potential (2010)				
Sub-Market	MT-gasifier/Biomass (ag waste)		Steam Turbine/Wood Waste	
Customer Peak Range (kW)	Number of Sites	MT-gasifier/Biomass (Ag Waste) Potential (MW)	Number of Sites	Steam Turbine Wood Waste Potential (MW)
100-500	223	10.6	NA	NA
501-1,000	32	8.0	NA	NA
1,001-2,500	14	6.7	NA	NA
2,501-5,000	NA	NA	3	3.9
5,001-10,000	NA	NA	0	0.0
Total (5 classes)	269	25.3	3	3.9

It should be noted that with regard to the wood industry, the number of candidate steam turbine (i.e., three) sites is so small that site-specific data becomes crucial to develop highly accurate estimates of potential DG installation.

3.5 DEVELOPMENT OF PORTFOLIOS

Once the technical potential of DG was estimated as described above, PA then sorted the technologies by LEC to determine the technologies that provided 579 MW at the least cost. These technologies are presented in Table 3-9. Since the quantity of renewable technologies available was less than 579 MW, PA included them all, as shown in Table 3-10.

Table 3-9
Least-Cost Portfolio

DG Technology	Application	DG Site Size (MW)	Fuel	Levelized Energy Cost (2004$/kWh)	Capacity Accreditation (MW)
2010					
Steam Turbines/Retro	CHP	5.0-10.0	Natural Gas	0.046	3.5
Steam Turbines/Retro	CHP	2.5-5.0	Natural Gas	0.047	1.5
Reciprocating Engines	CHP	5.0-10.0	Natural Gas	0.051	128.3
Steam Turbines/Retro	CHP	1.0-2.5	Natural Gas	0.052	5.0
Reciprocating Engines	CHP	2.5-5.0	Natural Gas	0.053	116.2
Reciprocating Engines	CHP	1.0-2.5	Natural Gas	0.054	94.5
Reciprocating Engines	CHP	0.5-1.0	Natural Gas	0.056	228.1
Reciprocating Engines	CHP	0.1-0.5	Natural Gas	0.057	119.4
					696.6
2013					
Steam Turbines/Retro	CHP	5.0-10.0	Natural Gas	0.045	3.6
Steam Turbines/Retro	CHP	2.5-5.0	Natural Gas	0.046	1.6
Reciprocating Engines	CHP	5.0-10.0	Natural Gas	0.048	145.4
Reciprocating Engines	CHP	2.5-5.0	Natural Gas	0.050	129.1
Steam Turbines/Retro	CHP	1.0-2.5	Natural Gas	0.050	5.3
Reciprocating Engines	CHP	1.0-2.5	Natural Gas	0.051	105.1
Reciprocating Engines	CHP	0.5-1.0	Natural Gas	0.052	251.8
					641.8

Table 3-10
Renewables Portfolio

DG Technology	Application	DG Site Size (MW)	Fuel	Levelized Energy Cost (2004$/kWh)	Capacity Accreditation (MW)
2010					
Wind Turbines	Power Only	2.5-5.0	Wind	0.068	0.5
Steam Turbines/New	Power Only	2.5-5.0	Biomass (wood waste)	0.070	3.9
Wind Turbines	Power Only	1.0-2.5	Wind	0.077	1.1
MT/Biogasifiers	Power Only	0.1-0.5	Biomass (ag waste)	0.082	10.6
Wind Turbines	Power Only	0.5-1.0	Wind	0.086	1.5
Wind Turbines	Power Only	0.1-0.5	Wind	0.105	3.0
					20.6
2013					
Wind Turbines	Power Only	2.5-5.0	Wind	0.065	0.5
Steam Turbines/New	Power Only	2.5-5.0	Biomass (wood waste)	0.070	4.1
MT/Biogasifiers	Power Only	1.0-2.5	Biomass (ag waste)	0.070	7.0
MT/Biogasifiers	Power Only	0.5-1.0	Biomass (ag waste)	0.071	8.3
Wind Turbines	Power Only	1.0-2.5	Wind	0.073	1.11
MT/Biogasifiers	Power Only	0.1-0.5	Biomass (ag waste)	0.075	11.1
Wind Turbines	Power Only	0.5-1.0	Wind	0.080	1.6
Wind Turbines	Power Only	0.1-0.5	Wind	0.098	3.1
					36.8

3.6 FACTORS INFLUENCING IMPLEMENTATION OF DG

The degree of implementation of DG is subject to numerous factors, some of which may be constraining, while others may enhance its potential. We discuss both aspects below.

First, as mentioned at the beginning of this section, PA's technical potential analysis was in large part statistical in nature. PA relied on the statistical customer consumption and load factor profile provided by Xcel. PA did not have access to any other customer or site-specific data, both of which can affect the size of the actual technical DG potential. PA also did not have any information on already installed DG systems. To the extent that there are, this would reduce our technical potential estimates. The following is a list of constraints that could limit the size of the potential for DG at Xcel:

- there was no information available on already installed DG systems. To the extent that such systems exist, this could reduce the estimated DG potential[26]
- site-specific space constraints can render impractical the installation of a DG system (especially in a retrofit CHP installation on a commercial or institutional site, or for wind-turbine installation on farms)
- site consumption patterns can constrain the technically-suitable size of a DG system. For instance, sites with a strong seasonal activity can result in too low load factors. In some cases, the actual E/T ratio can be significantly higher than typically encountered in the relevant industrial SIC as a result of decreasing steam consumption patterns on one hand, and increasing reliance on electric motors and controls on the other. In other cases, the annual load factor may be reasonably high but there are still extreme peak variations
- site thermal needs may not be suitable for some CHP DG system technologies depending on the quality and flow of steam required or the mix of steam vs. hot water needs
- access to natural gas may be unavailable (and an oil-fired system may not be considered as a viable alternative for locational, storage, code or safety reasons)
- access to biomass may not be feasible (for example, if the site waste is already used)
- siting of DG systems can be limited by environmental considerations (for example, when there is a cap on total new emissions from stationary power applications in a given territory)

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[26] Especially for CHP DG estimates (where the on-site steam needs could already be supplied by any existing DG system. Our power-only DG estimates would be less impacted since the data provided by Xcel shows the power consumption purchased from the utility, whether there is an existing DG system or not.

- finally, when such constraints do not preclude the practical installation of a DG system, they may instead render its capital cost or O&M cost too high to be economic.

On the other hand, implementation of DG can benefit from potential technical, economic and market improvements such as:

- higher DG technology efficiency performance as the result of better design and use of more effective materials
- further decreases in capital costs as more units are sold, or as manufacturing processes improve
- enhanced DG system packaging (resulting in smaller footprints and easier siting capability)
- enhanced environmental performance (e.g., either through better combustor configuration, improved combustion process, or more stringent after-combustion flue gas treatment)
- better market knowledge of DG system performance and how it can be applied
- faster DG technology commercialization as the result of more DG vendors being active in the market.

In sum, DG implementation is subject to a variety of factors that may enhance or constrain its introduction. Notwithstanding the noted constraints and enhancements, PA has attempted to balance these competing forces by the application of what we consider reasonable assumptions. Although possible, we have not modeled, nor was it appropriate to model given the scope of this study, any major dislocations in the market that would have a major constraining or enhancing effect on DG.

APPENDIX A: DESCRIPTION OF DG TECHNOLOGIES

This appendix provides a summary description of each generation technology initially considered in the study. As detailed earlier in the report, some of these did not pass our initial feasibility screens, and thus were not included in the numerical analysis.

A.1 RECIPROCATING ENGINES

Reciprocating internal combustion engines are a widespread and well-understood technology. The engines get their name from the "reciprocating," or back and forth motion, of the pistons in the engine cylinders. North American production exceeds 35 million units per year for automobiles, trucks, construction and mining equipment, marine propulsion, lawn care and a diverse set of power-generation applications. A variety of stationary engine products is available for a range of power-generation market applications and duty cycles, including standby and emergency power, peaking service, intermediate and base-load power and CHP. Reciprocating engines are available for electrical power generation applications using many different fuel sources in sizes ranging from a few kilowatts to more than 84 MW in individual applications.

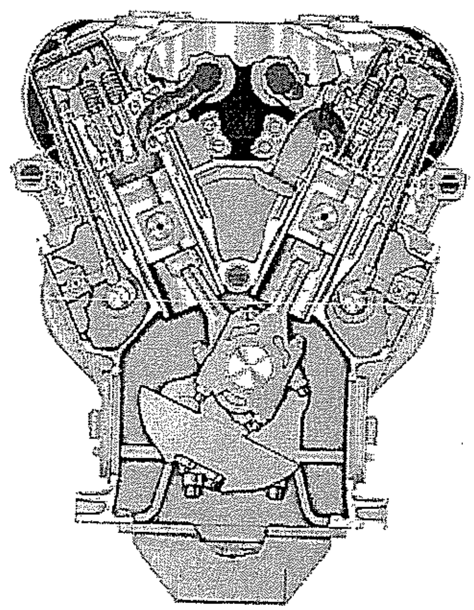


Figure 1. Reciprocating Engines (Source: Distributed Energy Forum)

There are two basic types of reciprocating engines – spark ignition (SI) and compression ignition (CI). Spark ignition engines for power generation use natural gas as the preferred fuel, although they can be set up to run on propane, gasoline, or special gases such as landfill, flare and digester gas. Compression ignition engines (often called diesel engines) operate on diesel fuel or heavy (residual) oil, or they can be set up to run in a dual-fuel configuration that burns primarily natural gas with a small amount of diesel pilot fuel for ignition or for backup in case the primary fuel becomes temporarily unavailable.

Diesel engines are the most popular type of reciprocating engine for both small and large power-generation applications. However, in the United States and other industrialized nations, diesel engines are increasingly restricted to emergency standby or limited duty-cycle service because of air emission concerns. As a result, the natural gas-fueled SI engine is now the engine of choice for the higher-duty-cycle stationary power market. Natural gas-fueled reciprocating engines are commercially available in sizes ranging from 10 kW to 7 MW.

Current generation natural gas engines offer low initial-cost, fast start-up, proven reliability when properly maintained, excellent load-following characteristics and significant heat-recovery potential. Electric efficiencies of natural gas engines can exceed 40% LHV for larger lean-burn engines (>2 MW).[1] Waste heat can be recovered from the engine exhaust and cooling systems to produce either hot water or low-pressure steam for CHP applications. Overall, CHP system efficiencies of 70% to 80% are routinely achieved with natural gas-engine systems in applications with electrical and heat loads appropriately in balance.[1]

Reciprocating engine technology has improved dramatically in the past three decades, driven by environmental and economic pressures. Computer systems and software have greatly advanced reciprocating engine design and control, accelerating advanced engine designs and making possible more precise control and diagnostic monitoring of engine operation. Stationary engine manufacturers continue to drive advanced engine technology.

The emissions signature of natural gas SI engines, in particular, has improved significantly in the past decade through better design and control of the combustion process and through the use of catalytic treatment of exhaust gases. Advanced lean-burn natural gas engines are available that produce untreated NOx levels as low as 50 ppmv @ 15% reference O_2 (dry basis). Three basic types of post-combustion catalytic control systems for reciprocating engines include [3]:

- ***Three-way catalyst (TWC) systems.*** reduce NOx, CO and unburned hydrocarbons by 90% or more. TWC systems are widely used for automotive applications.
- ***Selective catalytic reduction (SCR).*** SCR is normally used with relatively large (>2 MW) lean-burn reciprocating engines. In SCR, a NOx-reducing agent, such as ammonia is injected into the hot exhaust gas before it passes through a catalytic reactor. The NOx can be reduced by about 80-95%.
- ***Oxidation catalysts.*** Promote the oxidation of CO and unburned hydrocarbons to CO2 and water. CO conversions of 95% or more are readily achieved.

One example of reciprocating engine R&D is the Department of Energy's Advanced Reciprocating Engine Systems (ARES) program. DOE is leading a national effort to design, develop, test and demonstrate a new generation of reciprocating engine systems for DG applications that is cleaner, more reliable and efficient than current commercial products. Planned activities focus on the following performance targets for the next generation of reciprocating engines: high efficiency; environment; fuel flexibility; cost of power; and availability, reliability and maintainability. The goal is to maintain levels equivalent to current state-of-the-art systems.

A.2 COMBUSTION TURBINES

Conventional combustion turbine (CT) generators, also known as gas turbines, are a very mature technology. They typically range in size from about 1 MW up to 25 MW for DG and up to approximately 400 MW for central power generation. In this analysis, PA allowed for the possible development of smaller combustion turbines (as small as 500 kW) by estimating cost and performance characteristics based on larger currently commercially available machines. They are fueled by natural gas, oil, or a combination of fuels ("dual fuel"). Modern single-cycle combustion turbine units typically have efficiencies in the range of 30 to 45% at full load. Efficiency is somewhat lower at less than full load.

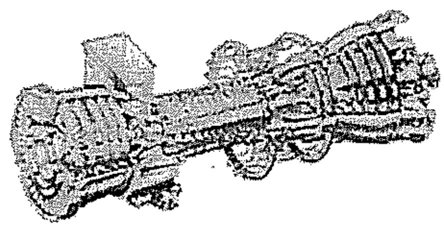


Figure 2. Combustion Turbine (Source: University of Florida)

Small combustion turbines are found in a broad array of applications including mechanical drives, base load grid-connected power generation, peaking power and remote off-grid applications. Gas turbines produce high-quality exhaust heat that can be used in CHP configurations to reach system efficiencies of 70% to 80%. Turbine-based CHP systems use turbine exhaust directly for industrial processes such as drying or as input into a heat recovery steam generator that produces steam for process or space conditioning use.

Gas turbines are one of the cleanest methods of generating electricity, with emissions of oxides of nitrogen (NOx) from some large turbines in the single-digit part-per-million (ppm) range, either with catalytic exhaust cleanup or lean premixed combustion. Because of their relatively high efficiency and reliance on natural gas as the primary fuel, gas turbines emit substantially less carbon dioxide (CO2) per kilowatt-hour generated than any other technology in general commercial use.

While CTs are often the technology of choice, there are some performance related drawbacks to CTs. These include [3]:

- part load efficiencies (50% load) are approximately 25% lower than full-load efficiencies
- CTs are rated based on standard conditions at sea level. Output and fuel consumption will decrease about 3.5% for every 1,000 feet above sea level
- CTs are rated at a nominal temperature of 59°F and their output decreases by 0.3 to 0.5% per °F increase in ambient temperature
- heat rate increases about 0.1 to 0.2% for every 1°F increase in turbine inlet temperature.

The Department of Energy (DOE) has been actively funding research and development aimed at improving combustion turbine performance for many years. The DOE's Advanced Turbine System research and development program is a partnership among the DOE, state governments, gas turbine manufactures, universities, natural gas companies, national laboratories and electric power producers. Together they are working on lower-cost, higher-efficiency gas turbines that have better environmental performance than existing machines.

A.3 STEAM TURBINES

Historically, steam turbines have been the primary power generation technology, providing mechanical and electric power and steam for a variety of industrial processes. Steam turbines are available in a wide range of sizes, from 500 kW to well over 1,400 MW. Unlike gas turbine and reciprocating engine CHP systems – in which heat is a byproduct of power generation – steam turbines normally generate electricity as a byproduct of steam generation.

Currently, steam turbine boilers can accommodate a wider variety of fuels than other available systems (including oil, natural or synthesis gas, coal, wood, solid waste, industrial byproducts and agricultural byproducts). However, individual boilers are usually only designed to accommodate two fuel sources at one time (i.e., dual-fueled boilers can be built to use oil or gas, coal or oil, gas or coal).

In general, steam turbine applications are driven by balancing lower-cost fuel, or avoided disposal costs for a waste fuel, against the high capital cost and (usually high) annual capacity factor for the steam plant and the combined energy plant-process plant application. For these reasons, steam turbines are not normally direct competitors of gas turbines and reciprocating engines in distributed generation applications, except where the primary fuel is not petroleum based.

While steam turbines are competitively priced compared to other technologies, the costs of the boiler, fuel handling and overall steam systems and the custom nature of most installations tend to drive up equipment costs. Thus in this analysis PA focused on steam turbine retrofits where an new steam turbine is added to a site with an existing boiler thereby lowering the capital cost. Low capital cost and the ability to use inexpensive fuels makes these projects very price competitive from a levelized cost perspective and environmentally attractive.

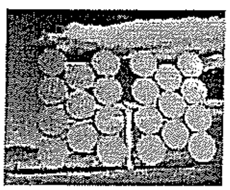
A.4 PHOTOVOLTAIC CELLS

Photovoltaic (PV) cells, or solar cells, convert sunlight directly into electricity without moving parts and without producing fuel wastes, air pollution, or greenhouse gases. PV cells are assembled into flat plate systems that are mounted in sunny areas. PV systems can be installed as either grid supply technologies or as customer-sited alternatives to purchased electricity. As suppliers of bulk grid power, PV modules would typically be installed in large array fields with total peak output a few megawatts. The DOE reports that very few of these systems have been installed to-date.[2]

The DOE reports that the cost of PV-generated electricity has dropped 15- to 20-fold; and grid-connected PV systems currently sell for about 20 to 50¢/kWh, including support structures, power conditioning and land.[3] They are highly reliable and last 20 years or longer.

Photovoltaic Overview	
Commercially available	Yes
Size Range	<1 kW - many MW
Fuel	Sunlight
Efficiency	5-15%
Environmental	No emissions
Commercial Status	Commercially deployed, advanced PV films under development
Source: California Energy Commission.	

At present, the marketplace appears focused on customer-sited systems, which may be installed to meet a variety of customer needs. These installations may be residential-size systems of just one kilowatt, or commercial-size systems of several hundred kilowatts.
A photovoltaic array surface area the size of roughly two football fields could produce 1 MW peak power.



A.5 CONCENTRATED PHOTOVOLTAIC

Concentrating Solar Power (CSP) systems concentrate solar energy 50 to 5,000 times to produce high temperature thermal energy, which is used to produce electricity. In CSP systems, highly reflective sun-tracking mirrors produce temperatures of 400ºC to 800ºC in the working fluid of a receiver, which is used in conventional heat engines (steam or gas turbines, or Stirling engines) to produce electricity at system solar-to-electric efficiencies of up to 30%. Systems using advanced photovoltaic PV cells may achieve efficiencies greater than 35%.[3]

The DOE reports that CSP technology is generally still too expensive to compete in widespread domestic markets without significant subsidies.[2] The DOE reports there are nine parabolic trough plants, with a total rated capacity of 354 MW, which were installed in California between 1985 and 1991. Their continuing operation has demonstrated their ability to achieve commercial costs of about 12¢/kWh to 14¢/kWh.[2]

A.6 MICRO TURBINES

Microturbines are small combustion turbines that currently produce between 25 kW and 500 kW, but may be capable of producing larger amounts by 2010. PA accounted for this possibility in the analysis detailed above by estimating cost and performance characteristics for larger micro turbines based on those available today.

Microturbines were derived from turbocharger technologies found in large trucks or the turbines in aircraft auxiliary power units (APUs). Most microturbines are single-stage; radial flow devices with high rotating speeds of 90,000 to 120,000 revolutions per minute. However, a few manufacturers have developed alternative systems with multiple stages and/or lower rotation speeds.[3]

Microturbines generally have marginally lower electrical efficiencies than similarly sized reciprocating engine generators. However, because of their design simplicity and relatively few moving parts, microturbines have the potential for simpler installation, higher reliability, reduced noise and vibration, lower maintenance requirements and possibly lower capital costs compared to reciprocating engines.

Long-term success will depend on early commercial success and rapidly growing sales to support large-volume production, an expanded sales and service infrastructure and continued technology development. Microturbines are nearing commercial status. However, many microturbine installations are still undergoing field tests or are part of large-scale demonstrations.[3]

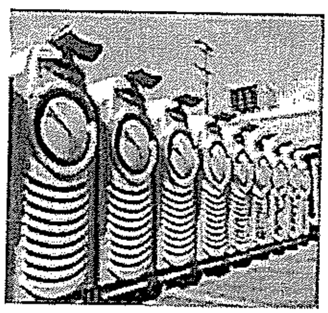


Figure 3. Microturbines (Source – Capstone)

Microturbine generators can be divided in two general classes:

- recuperated microturbines, which recover the heat from the exhaust gas to boost the temperature of combustion and increase the efficiency
- unrecuperated (or simple cycle) microturbines, which have lower efficiencies, but also lower capital costs.

While some early product introductions have featured unrecuperated designs, the bulk of developers' efforts are focused on recuperated systems. The recuperator recovers heat from the exhaust gas in order to boost the temperature of the air stream supplied to the combustor. Further exhaust heat recovery can be used in a CHP configuration.

Microturbines can be used for stand-by power, power quality and reliability, peak shaving and CHP applications. In addition, because microturbines are being developed to utilize a variety of fuels, they are being used for resource recovery and landfill gas applications. Microturbines are well suited for small commercial building establishments such as: restaurants, hotels/motels, small offices, retail stores and many others.

Microturbines also have significantly lower emissions signatures than reciprocating engines. Microturbine emissions can be up to eight times lower than diesel generators and currently available microturbine products produce less than 50% of the NOx emissions of a state-of-the-art natural gas lean-burn engine. In resource recovery applications, microturbines can burn waste gases that would otherwise be flared directly into the atmosphere.

Development is ongoing in a variety of areas:

- heat recovery/CHP
- fuel flexibility
- vehicles.

A.7 STIRLING ENGINES

Stirling engines are classed as external combustion engines. They are sealed systems with an inert working fluid, usually either helium or hydrogen. They are generally found in small sizes (1-25 kW) and are currently being produced in small quantities for specialized applications.

Recent interest in DG – and use by the space and marine industries – has revived interest in Stirling engines and as a result, research and development efforts have increased. Today, a search of the Internet produces more than 25 companies promoting the Stirling engine; but there has been little, if any, commercial success to date in power generation or CHP applications.[2]

While Stirling engines are worthy candidates for distributed generation and CHP applications, they face formidable hurdles in the marketplace. The incumbent reciprocating engine or gas turbine manufacturers have spent billions of dollars and decades in development. Capital costs of Stirling engines are relatively high ($2,000-$50,000/kW) and are generally not cost competitive with other DG technologies.[3] Most of the companies promoting Stirling engines for distributed generation have not progressed to a standard product line. Field demonstrations are few and far between – and field-test results are not being offered to the public.

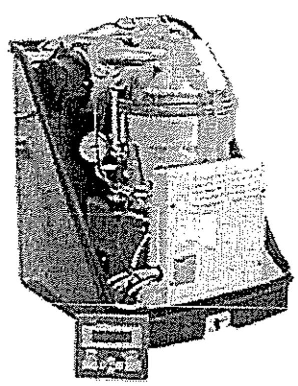


Figure 4. Overview of a Stirling Engine (Source: Whisper Tech Ltd.)

Stirling Engines Overview	
Commercially Available	No
Size Range	<1 kW - 25 kW
Fuel	Natural gas primarily but broad fuel flexibility is possible
Efficiency	12-20% (Target: >30%)
Environmental	Potential for very low emissions
Other Features	CHP (some models)
Commercial Status	Commercial availability 2005+
Source: California Energy Commission.	

Stirling engine developments have been directed at a wide range of applications, including [3]:

- small scale – residential or portable power generation
- solar dish applications – a renewable application where heat reflected from concentrating solar collectors is used to drive the Stirling engine. Several government-funded programs are aimed at enhancing this application
- vehicles – auto manufacturers along with the U.S. government are investigating utilizing Stirling engines in vehicles
- refrigeration – Stirling engines are being developed to provide cooling for applications such as microprocessors and superconductors
- aircraft – Stirling engines could provide a quieter-operating engine for small aircraft.

A.8 FUEL CELLS

Fuel cell systems, currently in the early stages of commercialization, are an entirely different approach to the production of electricity from traditional prime mover technologies. They are currently available in sizes from 100 kW to 2,000 kW, though the larger machines are not commercially viable as yet. Fuel cells are similar to batteries, in that both produce direct current (DC) electricity through an electrochemical process without direct combustion of a fuel source. However, whereas a battery delivers power from a finite amount of stored energy, fuel cells can operate indefinitely if a fuel and oxidant are continuously supplied.

There are four primary fuel cell technologies. These include phosphoric acid fuel cells (PAFC), molten carbonate fuel cells (MCFC), solid oxide fuel cells (SOFC) and proton exchange membrane fuel cells (PEMFC). The technologies are at varying states of development or commercialization. Fuel cell stacks utilize hydrogen and oxygen as the primary reactants. However, depending on the type of fuel processor and reformer used, fuel cells can use a number of fuel sources including gasoline, diesel, LNG, methane, methanol, natural gas, "waste gas" and solid carbon.

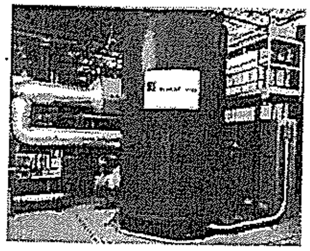


Figure 5. Fuel Cells (Source: National Energy Technology laboratory)

Fuel Cells Overview				
	PAFC	**SOFC**	**MCFC**	**PEMFC**
Commercially Available	Yes	No	Yes	Yes
Size Range	100-200 kW	1 kW - 100 kW	250 kW – 2 MW	3-250 1 kW
Fuel	Natural gas, landfill gas, digester gas, propane	Natural gas, hydrogen, landfill gas, fuel oil	Natural gas, hydrogen	Natural gas, hydrogen, propane, diesel
Efficiency	36-42%	45-60%	45-55%	25-40%
Environmental	Nearly zero emissions	Nearly zero emissions	Nearly zero emissions	Nearly zero emissions
Other Features	Cogen (hot water)	Cogen (hot water, LP or HP steam)	Cogen (hot water, LP or HP steam)	Cogen (80℃ water)
Commercial Status	Some commercially available	Some commercially available	Some commercially available	Some commercially available

Source: PA Consulting Group and California Energy Commission.

Natural gas (methane) is considered to be the most readily available and cleanest fuel (next to hydrogen) for distributed generation applications, so most research for stationary power systems is focused on converting natural gas into pure hydrogen fuel. This is particularly true for low-temperature fuel cells (PEMFC and PAFC). Here, fuel reformers use a catalytic reaction process to break the methane molecule and then separate hydrogen from carbon-based gases.

High temperature fuel cells such as the MCFC or the SOFC do not require a reformer since the high operating temperature of the fuel cell allows for the direct conversion of natural gas to hydrogen.

A.8.1 PAFC

There are well over 200 phosphoric acid fuel cells in service and much operating experience has been obtained. These fuel cells have been installed at medical, industrial and commercial facilities throughout the country and the 200 kW size is a good match for distributed generation applications. The operating temperature is about 400°F, which is suitable for co-generation applications.

Developers of PAFC are targeting commercial and light industrial applications in the 100-200 kW power range, for both electric-only and CHP applications. For these applications, PAFC has demonstrated the following favorable characteristics [3]:

- packaged systems with extremely high reliability (some have operated in the field for >9,000 hours of continuous service)
- very low noise and vibration
- negligible emissions
- high electrical efficiencies (36%-42%).

Researchers are currently working on fuel cell technologies that combine the benefits of PEMFC and PAFC into a single membrane that operates at intermediate temperatures of 90°C to 160°C. While often referred to as a "high temperature PEM," the devices can also be described as low temperature PAFC.

It is still too early to tell what the long-term impacts of this technology could be.

A.8.2 PEMFC

PEMFC technology development has been driven in large part by the automotive sector, where the PEMFCs have a compelling advantage over other fuel cell technologies in terms of their size and startup time (see table below).

Comparison of Fuel Cell Technologies

Fuel Cell Technology	Peak Power Density (MW/cm□)	System Efficiency (% HHV)	Start-up Time (hours)
PAFC	~200	36-45	1-4
MCFC	~160	43-55	10+
SOFC (tubular)	150-200	43-55	5-10
SOFC (planar)	200-500	43-55	unknown
PEMFC	~700	32-40	<0.1

Source: California Energy Commission.

Many of these attributes are also attractive for stationary markets and have encouraged developers to develop products for this sector. Products are being developed at the large end for commercial-sized power generation. The economic availability of natural gas makes this the fuel of choice. As with all fuel cell technologies, the need to reject system heat (in the form of hot water) makes them particularly attractive for CHP, which is included in almost all products currently under development.

PEM fuel cells are currently being developed for a broad range of applications including:

- automotive
- residential (<10 kW), both with and without CHP functionality
- commercial (10-250 kW), both with and without CHP functionality
- light industrial (250 kW and below), both with and without CHP functionality
- portable power (several kW and smaller).

Outstanding challenges for PEMFC systems are as follows [3]:

- For those systems operating at pressures > 1.5 atm, there is no compressor/expander product that can operate at appropriate airflows and efficiency to provide power to a PEMFC stack without imposing an unacceptable burden on system parasitic loads. This limitation has led many developers of stationary power systems to focus on near-ambient pressure operation.

- Long-term operation has yet to be demonstrated. Much of the current experience even on synthetic reformate has witnessed decays in power output over time, suggesting that more testing and product development will be critical.

- Long-term demonstration of CO control technology that can reliably produce acceptably low levels of CO remains to be done. While manufacturers have developed systems capable of producing 10-20 ppm CO, these results still need to be accomplished in long-term, real-world test environments.

- Operation of fully integrated systems in a broad range of thermal environments with adequate water recovery over extended periods has not yet been demonstrated.

Operation of fully integrated systems in environments where freezing temperatures occur over extended periods has not yet been demonstrated.

A.8.3 MCFC

The high efficiency and high operating temperature of MCFC units makes them most attractive for base-loaded power generation, either in electric-only or CHP modes.

Potential applications for MCFCs include:

- industrial
- government facilities
- universities
- hospitals.

MCFC technology has now been through several generations of field testing and additional testing continues. Future development is focusing on:

- extending stack life
- increasing the power density
- reducing the cost.

A.8.4 SOFC

Solid oxide fuel cells are being considered for a wide variety of applications, especially in the 5-250 kW size range:

- residential CHP
- small commercial buildings
- industrial facilities.

Larger sizes in the multi-megawatt range are being considered and would be used primarily for base-loaded utility applications.

With extensive demonstration experience accumulated on tubular SOFC technology, the primary development challenges relate to cost reduction. Additionally, as with all novel technologies, there remains a need to demonstrate the reliability and operating cost of these technologies prior to their commercialization.

For planar SOFC technologies, the primary challenges still relate to the difficulties maintaining the structural integrity of the units at their high operating temperatures. These issues are focused particularly on:

- maintenance of seals and manifolds under severe thermal stresses

- long-term mechanical integrity of planar systems in (as yet undemonstrated) field tests of integrated fuel cell stacks.

A.9 COMBINED HEAT & POWER

CHP systems, also known as CHP systems, simply capture and utilize excess heat generated during the production of electric power. CHP systems offer economic, environmental and reliability-related advantages compared to power generation facilities that produce only electricity. Distributed power generation systems, which are frequently located near thermal loads, are particularly well suited for CHP applications.

Market segments for CHP systems include:

- large and medium industrial systems – greater than 25 MW (too large for this study)
- small industrial system – 50 kW to 25 MW
- smaller commercial and institutional systems – 25 kW+
- residential – 1 kW to 25 kW (too small for this study).

Combined Heat & Power Overview	
Commercially Available	Yes
Size Range	Several kW – near 50 MW
Fuel	Depends on the DG technology
Efficiency	50-90%
Environmental	Reduces the use of excess fuel to produce heat.
Commercial Status	Many systems commercially available.
Source: California Energy Commission.	

The thermal energy recovered from distributed generators is typically in the form of steam or hot water. This thermal energy can in turn be used to meet thermal demands for the following applications:

- hot water production
- space heating
- hot air/steam for industrial process heat
- space cooling (requires an absorption chiller)
- dry air generation (with the use of a desiccant).

The form and quantity of recovered thermal energy produced by a CHP system is dependent on both the DG technology and the heat recovery hardware. The table below illustrates the CHP applications applicable to the different DG technologies.

DG Equipment in CHP Applications [3]

	Hot Water	Space Heating	Low-Pressure Steam	High-Pressure Steam	Space Cooling (single-stage absorption chiller)	Space Cooling (two-stage absorption chiller)	Dry Air (desiccant)
Reciprocating Engine	X	X	X	X	X	X	X
Stirling Engine	X	X			X		X
Microturbine	X	X	X		X		X
Combustion Turbine	X	X	X	X	X	X	X
PAFC	X	X					
PEMFC	X	X					
MCFC/SOFC	X	X	X	X	X	X	X

Manufacturers of DG equipment are shifting focus to create packaged CHP systems, where the heat recovery hardware is integrated with the power generation equipment and sold as a complete product. Currently, a large number of packaged CHP systems using reciprocating engines are becoming commercially available. Microturbine manufacturers are also adding heat recovery to their products. As the emerging technologies (i.e., fuel cells, Stirling engines) become more economical, integrated heat recovery will be added to the final commercial product.

A.10 WIND

Wind turbines use the wind to produce electrical power. As the turbine rotates in the wind, the generator produces electrical power. A single wind turbine can range in size from a few kW for residential applications to more than 5 MW.

Wind System Overview	
Commercially Available	Yes
Size Range	Several kW – 5 MW
Fuel	Wind
Efficiency	20-40%
Environmental	No emissions
Other Features	Various types and sizes
Source: California Energy Commission.	

Generally, individual wind turbines are grouped into wind farms containing several turbines. Wind farms can be quite large ranging from a few MW to tens of MW and may be connected directly to utility distribution systems. The larger wind farms are often connected to sub-transmission lines. The small-scale wind farms and individual units are typically defined as distributed generation. Residential systems (5-15 kW) are available; however they are generally not suitable for urban or small-lot suburban homes due to large space requirements.

Each part of the wind turbine is being subjected to research in order to improve efficiency and reduce costs. Several organizations, including the University of Colorado, are working to improve wind turbine generators to be more efficient. Some of the new technology that is being developed uses power electronics to allow for variable rotor speed operation to improve efficiency, control structural loads and improve power quality.

The airfoils for the wind turbine blades are also being improved to increase energy capture and improvements have been made to aerodynamics control devices that are built into the turbine blades to adjust the aerodynamic driving forces, optimize energy capture, control loads and control rotor speed.

Sources:

1. "Gas Fired Distributed Energy Resource Technology Characterizations," Gas Research Institute (GRI) and National Renewable Energy Laboratory (NREL), November 2003.

2. "Power Technologies Data Book," National Renewable Energy Laboratory (NREL), 2003 Edition

3. "Distributed Energy Resource Guide," California Energy Commission website http://www.energy.ca.gov/distgen/.

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Distributed Generation Technology				Total Capital Cost ($/kW)			O&M Costs ($/kWh)			Heat Rate (Btu/kWh)		
Technology	Application	Size	Fuel	2005	2010	2013	2005	2010	2013	2005	2010	2013
Fuel Cells	CHP	0.1 - 0.5 (MW)	Natural Gas	$ 4,250	$ 2,943	$ 2,314	$ 0.027	$ 0.020	$ 0.014	5,403	5,173	4,933
Fuel Cells	Power Only	0.1 - 0.5 (MW)	Natural Gas	$ 3,791	$ 2,568	$ 1,987	$ 0.027	$ 0.020	$ 0.014	8,420	8,007	7,843
Gas Turbines	CHP	0.1 - 0.5 (MW)	# 2	NA	NA	NA	NA	NA	NA	NA	NA	NA
Gas Turbines	CHP	0.1 - 0.5 (MW)	Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Gas Turbines	Power Only	0.1 - 0.5 (MW)	# 2	NA	NA	NA	NA	NA	NA	NA	NA	NA
Gas Turbines	Power Only	0.1 - 0.5 (MW)	Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
MicroTurbines	CHP	0.1 - 0.5 (MW)	Natural Gas	$ 1,663	$ 1,362	$ 1,204	$ 0.015	$ 0.015	$ 0.014	6,755	6,132	5,680
MicroTurbines	Power Only	0.1 - 0.5 (MW)	Natural Gas	$ 1,458	$ 1,177	$ 1,029	$ 0.015	$ 0.015	$ 0.014	11,375	9,480	8,220
Reciprocating Engines	CHP	0.1 - 0.5 (MW)	# 2	$ 1,348	$ 1,169	$ 1,084	$ 0.014	$ 0.012	$ 0.011	4,712	4,600	4,558
Reciprocating Engines	CHP	0.1 - 0.5 (MW)	Natural Gas	$ 1,348	$ 1,169	$ 1,084	$ 0.014	$ 0.012	$ 0.011	4,712	4,600	4,558
Reciprocating Engines	CHP	0.1 - 0.5 (MW)	Biodiesel	$ 1,348	$ 1,169	$ 1,084	$ 0.014	$ 0.012	$ 0.011	4,712	4,600	4,558
Reciprocating Engines	Power Only	0.1 - 0.5 (MW)	# 2	$ 888	$ 794	$ 748	$ 0.012	$ 0.011	$ 0.010	10,837	10,447	10,142
Reciprocating Engines	Power Only	0.1 - 0.5 (MW)	Natural Gas	$ 888	$ 794	$ 748	$ 0.012	$ 0.011	$ 0.010	10,837	10,447	10,142
Reciprocating Engines	Power Only	0.1 - 0.5 (MW)	Biodiesel	$ 888	$ 794	$ 748	$ 0.012	$ 0.011	$ 0.010	10,837	10,447	10,142
Steam Turbines/Retro	CHP	0.1 - 0.5 (MW)	Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Steam Turbines	Power Only	0.1 - 0.5 (MW)	Steam	NA	NA	NA	NA	NA	NA	NA	NA	NA
Fuel Cells	CHP	0.5 - 1.0 (MW)	Natural Gas	$ 4,250	$ 2,943	$ 2,314	$ 0.027	$ 0.020	$ 0.014	5,403	5,173	4,933
Fuel Cells	Power Only	0.5 - 1.0 (MW)	Natural Gas	$ 3,946	$ 2,684	$ 2,085	$ 0.027	$ 0.020	$ 0.014	8,420	8,007	7,843
Gas Turbines	CHP	0.5 - 1.0 (MW)	# 2	$ 1,928	$ 1,789	$ 1,691	$ 0.010	$ 0.008	$ 0.008	6,859	6,569	6,305
Gas Turbines	CHP	0.5 - 1.0 (MW)	Natural Gas	$ 1,928	$ 1,789	$ 1,691	$ 0.010	$ 0.008	$ 0.008	6,859	6,569	6,305
Gas Turbines	Power Only	0.5 - 1.0 (MW)	# 2	$ 1,623	$ 1,529	$ 1,454	$ 0.010	$ 0.009	$ 0.009	14,868	14,076	13,462
Gas Turbines	Power Only	0.5 - 1.0 (MW)	Natural Gas	$ 1,623	$ 1,529	$ 1,454	$ 0.010	$ 0.009	$ 0.009	14,868	14,076	13,462
MicroTurbines	CHP	0.5 - 1.0 (MW)	Natural Gas	NA	$ 1,181	$ 1,105	NA	$ 0.015	$ 0.015	-	5,915	5,863
MicroTurbines	Power Only	0.5 - 1.0 (MW)	Natural Gas	NA	$ 996	$ 927	NA	$ 0.015	$ 0.015	-	9,480	9,338
Reciprocating Engines	CHP	0.5 - 1.0 (MW)	# 2	$ 1,245	$ 1,107	$ 1,040	$ 0.012	$ 0.011	$ 0.010	4,895	4,774	4,691
Reciprocating Engines	CHP	0.5 - 1.0 (MW)	Natural Gas	$ 1,245	$ 1,107	$ 1,040	$ 0.012	$ 0.011	$ 0.010	4,895	4,774	4,691
Reciprocating Engines	CHP	0.5 - 1.0 (MW)	Biodiesel	$ 1,245	$ 1,107	$ 1,040	$ 0.012	$ 0.011	$ 0.010	4,895	4,774	4,691
Reciprocating Engines	Power Only	0.5 - 1.0 (MW)	# 2	$ 847	$ 773	$ 737	$ 0.010	$ 0.009	$ 0.009	10,375	9,947	9,614
Reciprocating Engines	Power Only	0.5 - 1.0 (MW)	Natural Gas	$ 847	$ 773	$ 737	$ 0.010	$ 0.009	$ 0.009	10,375	9,947	9,614
Reciprocating Engines	Power Only	0.5 - 1.0 (MW)	Biodiesel	$ 847	$ 773	$ 737	$ 0.010	$ 0.009	$ 0.009	10,375	9,947	9,614
Steam Turbines/Retro	CHP	0.5 - 1.0 (MW)	Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Steam Turbines	Power Only	0.5 - 1.0 (MW)	Steam	NA	NA	NA	NA	NA	NA	NA	NA	NA
Fuel Cells	CHP	1.0 - 2.5 (MW)	Natural Gas	$ 3,337	$ 2,464	$ 2,495	$ 0.034	$ 0.020	$ 0.016	5,200	4,980	4,852
Fuel Cells	Power Only	1.0 - 2.5 (MW)	Natural Gas	$ 3,117	$ 2,268	$ 1,993	$ 0.034	$ 0.020	$ 0.016	7,420	7,110	6,930
Gas Turbines	CHP	1.0 - 2.5 (MW)	# 2	$ 1,688	$ 1,564	$ 1,478	$ 0.009	$ 0.008	$ 0.007	6,639	6,352	6,087
Gas Turbines	CHP	1.0 - 2.5 (MW)	Natural Gas	$ 1,688	$ 1,564	$ 1,478	$ 0.009	$ 0.008	$ 0.007	6,639	6,352	6,087
Gas Turbines	Power Only	1.0 - 2.5 (MW)	# 2	$ 1,468	$ 1,368	$ 1,294	$ 0.009	$ 0.009	$ 0.009	14,111	13,352	12,763
Gas Turbines	Power Only	1.0 - 2.5 (MW)	Natural Gas	$ 1,468	$ 1,368	$ 1,294	$ 0.009	$ 0.009	$ 0.009	14,111	13,352	12,763
MicroTurbines	CHP	1.0 - 2.5 (MW)	Natural Gas	NA	$ 1,181	$ 1,105	NA	$ 0.015	$ 0.015	-	5,915	5,863
MicroTurbines	Power Only	1.0 - 2.5 (MW)	Natural Gas	NA	$ 996	$ 927	NA	$ 0.015	$ 0.015	-	9,480	9,338
Reciprocating Engines	CHP	1.0 - 2.5 (MW)	# 2	$ 1,047	$ 989	$ 958	$ 0.009	$ 0.009	$ 0.008	5,246	5,108	4,946
Reciprocating Engines	CHP	1.0 - 2.5 (MW)	Natural Gas	$ 1,047	$ 989	$ 958	$ 0.009	$ 0.009	$ 0.008	5,246	5,108	4,946
Reciprocating Engines	CHP	1.0 - 2.5 (MW)	Biodiesel	$ 1,047	$ 989	$ 958	$ 0.009	$ 0.009	$ 0.008	5,246	5,108	4,946
Reciprocating Engines	Power Only	1.0 - 2.5 (MW)	# 2	$ 827	$ 793	$ 775	$ 0.009	$ 0.009	$ 0.009	9,465	8,968	8,583
Reciprocating Engines	Power Only	1.0 - 2.5 (MW)	Natural Gas	$ 827	$ 793	$ 775	$ 0.009	$ 0.009	$ 0.009	9,465	8,968	8,583
Reciprocating Engines	Power Only	1.0 - 2.5 (MW)	Biodiesel	$ 827	$ 793	$ 775	$ 0.009	$ 0.009	$ 0.009	9,465	8,968	8,583

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Distributed Generation Technology				Total Capital Cost ($/kW)			O&M Costs ($/kWh)			Heat Rate (Btu/kWh)		
Technology	Application	Size	Fuel	2005	2010	2013	2005	2010	2013	2005	2010	2013
Steam Turbines/Retro	CHP	1.0 - 2.5 (MW)	Natural Gas	$ 671	$ 644	$ 634	$ 0.015	$ 0.015	$ 0.015	4,544	4,509	4,496
Steam Turbines	Power Only	1.0 - 2.5 (MW)	Steam	NA	NA	NA	NA	NA	NA	NA	NA	NA
Fuel Cells	CHP	2.5 - 5.0 (MW)	Natural Gas	$ 3,337	$ 2,464	$ 2,176	$ 0.034	$ 0.020	$ 0.016	5,200	4,980	4,892
Fuel Cells	Power Only	2.5 - 5.0 (MW)	Natural Gas	$ 3,116	$ 2,269	$ 1,995	$ 0.034	$ 0.020	$ 0.016	7,420	7,110	6,987
Gas Turbines	CHP	2.5 - 5.0 (MW)	# 2	$ 1,436	$ 1,337	$ 1,268	$ 0.008	$ 0.006	$ 0.006	6,386	6,140	5,919
Gas Turbines	CHP	2.5 - 5.0 (MW)	Natural Gas	$ 1,436	$ 1,337	$ 1,268	$ 0.008	$ 0.006	$ 0.006	6,386	6,140	5,919
Gas Turbines	Power Only	2.5 - 5.0 (MW)	# 2	$ 1,215	$ 1,142	$ 1,087	$ 0.006	$ 0.005	$ 0.005	13,205	12,523	11,990
Gas Turbines	Power Only	2.5 - 5.0 (MW)	Natural Gas	$ 1,215	$ 1,142	$ 1,087	$ 0.006	$ 0.005	$ 0.005	13,205	12,523	11,990
MicroTurbines	CHP	2.5 - 5.0 (MW)	Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
MicroTurbines	Power Only	2.5 - 5.0 (MW)	Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Reciprocating Engines	CHP	2.5 - 5.0 (MW)	# 2	$ 1,031	$ 970	$ 937	$ 0.009	$ 0.008	$ 0.008	5,197	5,049	4,873
Reciprocating Engines	CHP	2.5 - 5.0 (MW)	Natural Gas	$ 1,031	$ 970	$ 937	$ 0.009	$ 0.008	$ 0.008	5,197	5,049	4,873
Reciprocating Engines	CHP	2.5 - 5.0 (MW)	Biodiesel	$ 1,031	$ 970	$ 937	$ 0.009	$ 0.008	$ 0.008	5,197	5,049	4,873
Reciprocating Engines	Power Only	2.5 - 5.0 (MW)	# 2	$ 804	$ 769	$ 750	$ 0.008	$ 0.008	$ 0.008	9,104	8,642	8,258
Reciprocating Engines	Power Only	2.5 - 5.0 (MW)	Natural Gas	$ 804	$ 769	$ 750	$ 0.008	$ 0.008	$ 0.008	9,104	8,642	8,258
Reciprocating Engines	Power Only	2.5 - 5.0 (MW)	Biodiesel	$ 804	$ 769	$ 750	$ 0.008	$ 0.008	$ 0.008	9,104	8,642	8,258
Steam Turbines/Retro	CHP	2.5 - 5.0 (MW)	Natural Gas	$ 396	$ 386	$ 382	$ 0.013	$ 0.013	$ 0.013	4,570	4,547	4,539
Steam Turbines	Power Only	2.5 - 5.0 (MW)	Steam	NA	NA	NA	NA	NA	NA	NA	NA	NA
Fuel Cells	CHP	5.0 - 10.0 (MW)	Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Fuel Cells	Power Only	5.0 - 10.0 (MW)	Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Gas Turbines	CHP	5.0 - 10.0 (MW)	# 2	$ 994	$ 948	$ 917	$ 0.005	$ 0.005	$ 0.005	5,853	5,696	5,588
Gas Turbines	CHP	5.0 - 10.0 (MW)	Natural Gas	$ 994	$ 948	$ 917	$ 0.005	$ 0.005	$ 0.005	5,853	5,696	5,588
Gas Turbines	Power Only	5.0 - 10.0 (MW)	# 2	$ 846	$ 826	$ 810	$ 0.005	$ 0.005	$ 0.005	11,300	10,800	10,400
Gas Turbines	Power Only	5.0 - 10.0 (MW)	Natural Gas	$ 846	$ 826	$ 810	$ 0.005	$ 0.005	$ 0.005	11,300	10,800	10,400
MicroTurbines	CHP	5.0 - 10.0 (MW)	Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
MicroTurbines	Power Only	5.0 - 10.0 (MW)	Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Reciprocating Engines	CHP	5.0 - 10.0 (MW)	# 2	$ 992	$ 931	$ 897	$ 0.008	$ 0.008	$ 0.008	4,999	4,822	4,729
Reciprocating Engines	CHP	5.0 - 10.0 (MW)	Natural Gas	$ 992	$ 931	$ 897	$ 0.008	$ 0.008	$ 0.008	4,999	4,822	4,729
Reciprocating Engines	CHP	5.0 - 10.0 (MW)	Biodiesel	$ 992	$ 931	$ 897	$ 0.008	$ 0.008	$ 0.008	4,999	4,822	4,729
Reciprocating Engines	Power Only	5.0 - 10.0 (MW)	# 2	$ 783	$ 748	$ 728	$ 0.008	$ 0.008	$ 0.008	8,749	8,322	7,955
Reciprocating Engines	Power Only	5.0 - 10.0 (MW)	Natural Gas	$ 783	$ 748	$ 728	$ 0.008	$ 0.008	$ 0.008	8,749	8,322	7,955
Reciprocating Engines	Power Only	5.0 - 10.0 (MW)	Biodiesel	$ 783	$ 748	$ 728	$ 0.008	$ 0.008	$ 0.008	8,749	8,322	7,955
Steam Turbines/Retro	CHP	5.0 - 10.0 (MW)	Natural Gas	$ 382	$ 376	$ 373	$ 0.013	$ 0.013	$ 0.013	4,388	4,388	4,388
Steam Turbines	Power Only	5.0 - 10.0 (MW)	Steam	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wind Turbines	Power Only	0.1 - 0.5 (MW)	Wind	$ 1,800	$ 1,500	$ 1,425	$ 0.0270	$ 0.0225	$ 0.0200	NA	NA	NA
Wind Turbines	Power Only	0.5 - 1.0 (MW)	Wind	$ 1,400	$ 1,350	$ 1,250	$ 0.014	$ 0.012	$ 0.011	NA	NA	NA
Wind Turbines	Power Only	1.0 - 2.5 (MW)	Wind	$ 1,350	$ 1,200	$ 1,150	$ 0.012	$ 0.011	$ 0.010	NA	NA	NA
Wind Turbines	Power Only	2.5 - 5.0 (MW)	Wind	$ 1,125	$ 1,075	$ 1,050	$ 0.010	$ 0.009	$ 0.008	NA	NA	NA
Wind Turbines	Power Only	5.0 - 10.0 (MW)	Wind	$ 952	$ 946	$ 940	$ 0.009	$ 0.008	$ 0.006	NA	NA	NA
MT/Biogasifiers	Power Only	0.1 - 0.5 (MW)	Biomass 1	$ 2,308	$ 2,160	$ 1,930	$ 0.0254	$ 0.0244	$ 0.0231	16,406	13,725	11,850
MT/Biogasifiers	Power Only	0.5 - 1.0 (MW)	Biomass 1	NA	NA	$ 1,690	NA	NA	$ 0.023	NA	NA	11,850
MT/Biogasifiers	Power Only	1.0 - 2.5 (MW)	Biomass 1	NA	NA	$ 1,615	NA	NA	$ 0.023	NA	NA	11,850
Steam Turbines/New	Power Only	2.5 - 5.0 (MW)	Biomass 2	$ 1,571	$ 1,400	$ 1,376	$ 0.016	$ 0.016	$ 0.016	12,398	12,328	12,102
Steam Turbines/New	Power Only	5.0 - 10.0 (MW)	Biomass 2	$ 1,571	$ 1,400	$ 1,376	$ 0.016	$ 0.016	$ 0.016	12,398	12,328	12,102

Distributed Generation Technology				E/T Ratio			Adjusted DG Fuel Cost ($/Million Btu)			LEC ($/kWh)		
Technology	Application	Size	Fuel	2005	2010	2013	2005	2010	2013	2005	2010	2013
Fuel Cells	CHP	0.1 - 0.5 (MW)	Natural Gas	1.563	1.697	1.755	$7.61	$6.33	$6.00	0.123	0.090	0.073
Fuel Cells	Power Only	0.1 - 0.5 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	0.140	0.103	0.086
Gas Turbines	CHP	0.1 - 0.5 (MW)	# 2	NA	NA	NA	$7.91	$7.07	$6.99	NA	NA	NA
Gas Turbines	CHP	0.1 - 0.5 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	NA	NA	NA
Gas Turbines	Power Only	0.1 - 0.5 (MW)	# 2	NA	NA	NA	$7.91	$7.07	$6.99	NA	NA	NA
Gas Turbines	Power Only	0.1 - 0.5 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	NA	NA	NA
MicroTurbines	CHP	0.1 - 0.5 (MW)	Natural Gas	0.920	1.280	1.636	$7.61	$6.33	$6.00	0.088	0.071	0.064
MicroTurbines	Power Only	0.1 - 0.5 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	0.121	0.090	0.077
Reciprocating Engines	CHP	0.1 - 0.5 (MW)	# 2	0.713	0.759	0.797	$7.91	$7.07	$6.99	0.069	0.060	0.057
Reciprocating Engines	CHP	0.1 - 0.5 (MW)	Natural Gas	0.713	0.759	0.797	$7.61	$6.33	$6.00	0.067	0.057	0.052
Reciprocating Engines	CHP	0.1 - 0.5 (MW)	Biodiesel	0.713	0.759	0.797	$8.10	$7.24	$7.16	0.070	0.061	0.057
Reciprocating Engines	Power Only	0.1 - 0.5 (MW)	# 2	NA	NA	NA	$7.91	$7.07	$6.99	0.109	0.095	0.091
Reciprocating Engines	Power Only	0.1 - 0.5 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	0.106	0.088	0.081
Reciprocating Engines	Power Only	0.1 - 0.5 (MW)	Biodiesel	NA	NA	NA	$8.10	$7.24	$7.16	0.111	0.097	0.093
Steam Turbines/Retro	CHP	0.1 - 0.5 (MW)	Natural Gas	NA	NA	NA	$0.00	$0.00	$0.00	NA	NA	NA
Steam Turbines	Power Only	0.1 - 0.5 (MW)	Steam	NA	NA	NA	$0.00	$0.00	$0.00	NA	NA	NA
Fuel Cells	CHP	0.5 - 1.0 (MW)	Natural Gas	1.563	1.697	1.755	$7.61	$6.33	$6.00	0.123	0.090	0.073
Fuel Cells	Power Only	0.5 - 1.0 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	0.142	0.105	0.088
Gas Turbines	CHP	0.5 - 1.0 (MW)	# 2	0.533	0.570	0.598	$7.91	$7.07	$6.99	0.089	0.078	0.074
Gas Turbines	CHP	0.5 - 1.0 (MW)	Natural Gas	0.533	0.570	0.598	$7.61	$6.33	$6.00	0.087	0.073	0.067
Gas Turbines	Power Only	0.5 - 1.0 (MW)	# 2	NA	NA	NA	$7.91	$7.07	$6.99	0.148	0.129	0.122
Gas Turbines	Power Only	0.5 - 1.0 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	0.144	0.118	0.109
MicroTurbines	CHP	0.5 - 1.0 (MW)	Natural Gas	-	1.200	1.236	$7.61	$6.33	$6.00	NA	0.068	0.064
MicroTurbines	Power Only	0.5 - 1.0 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	NA	0.088	0.083
Reciprocating Engines	CHP	0.5 - 1.0 (MW)	# 2	0.813	0.877	0.926	$7.91	$7.07	$6.99	0.067	0.059	0.056
Reciprocating Engines	CHP	0.5 - 1.0 (MW)	Natural Gas	0.813	0.877	0.926	$7.61	$6.33	$6.00	0.066	0.056	0.052
Reciprocating Engines	CHP	0.5 - 1.0 (MW)	Biodiesel	0.813	0.877	0.926	$8.10	$7.24	$7.16	0.068	0.060	0.057
Reciprocating Engines	Power Only	0.5 - 1.0 (MW)	# 2	NA	NA	NA	$7.91	$7.07	$6.99	0.103	0.090	0.085
Reciprocating Engines	Power Only	0.5 - 1.0 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	0.100	0.082	0.076
Reciprocating Engines	Power Only	0.5 - 1.0 (MW)	Biodiesel	NA	NA	NA	$8.10	$7.24	$7.16	0.105	0.091	0.087
Steam Turbines/Retro	CHP	0.5 - 1.0 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	NA	NA	NA
Steam Turbines	Power Only	0.5 - 1.0 (MW)	Steam	NA	NA	NA	$0.00	$0.00	$0.00	NA	NA	NA
Fuel Cells	CHP	1.0 - 2.5 (MW)	Natural Gas	1.920	2.000	2.050	$7.61	$6.33	$6.00	0.117	0.083	0.077
Fuel Cells	Power Only	1.0 - 2.5 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	0.131	0.094	0.083
Gas Turbines	CHP	1.0 - 2.5 (MW)	# 2	0.578	0.618	0.648	$7.91	$7.07	$6.99	0.084	0.073	0.069
Gas Turbines	CHP	1.0 - 2.5 (MW)	Natural Gas	0.578	0.618	0.648	$7.61	$6.33	$6.00	0.082	0.068	0.063
Gas Turbines	Power Only	1.0 - 2.5 (MW)	# 2	NA	NA	NA	$7.91	$7.07	$6.99	0.140	0.121	0.115
Gas Turbines	Power Only	1.0 - 2.5 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$5.00	0.135	0.111	0.102
MicroTurbines	CHP	1.0 - 2.5 (MW)	Natural Gas	-	1.200	1.236	$7.61	$6.33	$6.00	NA	0.068	0.064
MicroTurbines	Power Only	1.0 - 2.5 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	NA	0.088	0.083
Reciprocating Engines	CHP	1.0 - 2.5 (MW)	# 2	1.011	1.111	1.181	$7.91	$7.07	$6.99	0.064	0.058	0.055
Reciprocating Engines	CHP	1.0 - 2.5 (MW)	Natural Gas	1.011	1.111	1.181	$7.61	$6.33	$6.00	0.062	0.054	0.051
Reciprocating Engines	CHP	1.0 - 2.5 (MW)	Biodiesel	1.011	1.111	1.181	$8.10	$7.24	$7.16	0.065	0.058	0.056
Reciprocating Engines	Power Only	1.0 - 2.5 (MW)	# 2	NA	NA	NA	$7.91	$7.07	$6.99	0.095	0.083	0.079
Reciprocating Engines	Power Only	1.0 - 2.5 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	0.092	0.076	0.070
Reciprocating Engines	Power Only	1.0 - 2.5 (MW)	Biodiesel	NA	NA	NA	$8.10	$7.24	$7.16	0.097	0.084	0.080

PA

Distributed Generation Technology				E/T Ratio			Adjusted DG Fuel Cost ($/Million Btu)			LEC ($/kWh)		
Technology	Application	Size	Fuel	2005	2010	2013	2005	2010	2013	2005	2010	2013
Steam Turbines/Retro	CHP	1.0 - 2.5 (MW)	Natural Gas	0.095	0.095	0.095	$7.61	$6.33	$6.00	0.058	0.052	0.050
Steam Turbines	Power Only	1.0 - 2.5 (MW)	Steam	NA	NA	NA	$0.00	$0.00	$0.00	NA	NA	NA
Fuel Cells	CHP	2.5 - 5.0 (MW)	Natural Gas	1.920	2.000	2.050	$7.61	$6.33	$6.00	0.117	0.083	0.073
Fuel Cells	Power Only	2.5 - 5.0 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	0.131	0.094	0.083
Gas Turbines	CHP	2.5 - 5.0 (MW)	# 2	0.636	0.683	0.720	$7.91	$7.07	$6.99	0.077	0.067	0.064
Gas Turbines	CHP	2.5 - 5.0 (MW)	Natural Gas	0.636	0.683	0.720	$7.61	$6.33	$6.00	0.075	0.063	0.058
Gas Turbines	Power Only	2.5 - 5.0 (MW)	# 2	NA	NA	NA	$7.91	$7.07	$6.99	0.126	0.109	0.103
Gas Turbines	Power Only	2.5 - 5.0 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	0.122	0.099	0.091
MicroTurbines	CHP	2.5 - 5.0 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	NA	NA	NA
MicroTurbines	Power Only	2.5 - 5.0 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	NA	NA	NA
Reciprocating Engines	CHP	2.5 - 5.0 (MW)	# 2	1.095	1.190	1.265	$7.91	$7.07	$6.99	0.063	0.057	0.055
Reciprocating Engines	CHP	2.5 - 5.0 (MW)	Natural Gas	1.095	1.190	1.265	$7.61	$6.33	$6.00	0.061	0.05294	0.050
Reciprocating Engines	CHP	2.5 - 5.0 (MW)	Biodiesel	1.095	1.190	1.265	$8.10	$7.24	$7.16	0.064	0.058	0.055
Reciprocating Engines	Power Only	2.5 - 5.0 (MW)	# 2	NA	NA	NA	$7.91	$7.07	$6.99	0.091	0.079	0.076
Reciprocating Engines	Power Only	2.5 - 5.0 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	0.088	0.073	0.067
Reciprocating Engines	Power Only	2.5 - 5.0 (MW)	Biodiesel	NA	NA	NA	$8.10	$7.24	$7.16	0.092	0.081	0.077
Steam Turbines/Retro	CHP	2.5 - 5.0 (MW)	Natural Gas	0.100	0.100	0.100	$7.61	$6.33	$6.00	0.053	0.047	0.046
Steam Turbines	Power Only	2.5 - 5.0 (MW)	Steam	NA	NA	NA	$0.00	$0.00	$0.00	NA	NA	NA
Fuel Cells	CHP	5.0 - 10.0 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	NA	NA	NA
Fuel Cells	Power Only	5.0 - 10.0 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	NA	NA	NA
Gas Turbines	CHP	5.0 - 10.0 (MW)	# 2	0.780	0.840	0.894	$7.91	$7.07	$6.99	0.064	0.058	0.056
Gas Turbines	CHP	5.0 - 10.0 (MW)	Natural Gas	0.780	0.840	0.894	$7.61	$6.33	$6.00	0.063	0.053	0.050
Gas Turbines	Power Only	5.0 - 10.0 (MW)	# 2	NA	NA	NA	$7.91	$7.07	$6.99	0.105	0.092	0.088
Gas Turbines	Power Only	5.0 - 10.0 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	0.102	0.084	0.078
MicroTurbines	CHP	5.0 - 10.0 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	NA	NA	NA
MicroTurbines	Power Only	5.0 - 10.0 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	NA	NA	NA
Reciprocating Engines	CHP	5.0 - 10.0 (MW)	# 2	1.140	1.220	1.322	$7.91	$7.07	$6.99	0.061	0.054	0.053
Reciprocating Engines	CHP	5.0 - 10.0 (MW)	Natural Gas	1.140	1.220	1.322	$7.61	$6.33	$6.00	0.059	0.051	0.048
Reciprocating Engines	CHP	5.0 - 10.0 (MW)	Biodiesel	1.140	1.220	1.322	$8.10	$7.24	$7.16	0.062	0.055	0.054
Reciprocating Engines	Power Only	5.0 - 10.0 (MW)	# 2	NA	NA	NA	$7.91	$7.07	$6.99	0.088	0.077	0.073
Reciprocating Engines	Power Only	5.0 - 10.0 (MW)	Natural Gas	NA	NA	NA	$7.61	$6.33	$6.00	0.085	0.071	0.065
Reciprocating Engines	Power Only	5.0 - 10.0 (MW)	Biodiesel	NA	NA	NA	$8.10	$7.24	$7.16	0.089	0.078	0.075
Steam Turbines/Retro	CHP	5.0 - 10.0 (MW)	Natural Gas	0.111	0.111	0.111	$7.61	$6.33	$6.00	0.052	0.046	0.045
Steam Turbines	Power Only	5.0 - 10.0 (MW)	Steam	NA	NA	NA	$0.00	$0.00	$0.00	NA	NA	NA
Wind Turbines	Power Only	0.1 - 0.5 (MW)	Wind	NA	NA	NA	NA	NA	NA	0.126	0.105	0.098
Wind Turbines	Power Only	0.5 - 1.0 (MW)	Wind	NA	NA	NA	NA	NA	NA	0.091	0.086	0.080
Wind Turbines	Power Only	1.0 - 2.5 (MW)	Wind	NA	NA	NA	NA	NA	NA	0.086	0.077	0.073
Wind Turbines	Power Only	2.5 - 5.0 (MW)	Wind	NA	NA	NA	NA	NA	NA	0.072	0.068	0.065
Wind Turbines	Power Only	5.0 - 10.0 (MW)	Wind	NA	NA	NA	NA	NA	NA	0.061	0.060	0.058
MT/Biogasifiers	Power Only	0.1 - 0.5 (MW)	Biomass 1	NA	NA	NA	$1.96	$2.06	$2.12	0.089	0.082	0.075
MT/Biogasifiers	Power Only	0.5 - 1.0 (MW)	Biomass 1	NA	NA	NA	$1.96	$2.06	$2.12	NA	NA	0.071
MT/Biogasifiers	Power Only	1.0 - 2.5 (MW)	Biomass 1	NA	NA	NA	$1.96	$2.06	$2.12	NA	NA	0.070
Steam Turbines/New	Power Only	2.5 - 5.0 (MW)	Biomass 2	NA	NA	NA	$2.65	$2.78	$2.87	0.070	0.070	0.070
Steam Turbines/New	Power Only	5.0 - 10.0 (MW)	Biomass 2	NA	NA	NA	$2.65	$2.78	$2.87	0.070	0.070	0.070

APPENDIX C: NATURAL GAS AND OIL PRICE FORECAST

Fuel Prices Applied ($ / MMbtu)

	#2 Oil		Natural Gas	
	Nominal	2004$	Nominal	2004$
2005	8.07	7.91	7.76	7.61
2006	7.79	7.49	7.67	7.37
2007	7.53	7.10	7.27	6.86
2008	7.68	7.10	7.26	6.71
2009	7.83	7.09	7.08	6.41
2010	7.99	7.07	7.15	6.33
2011	8.15	7.04	7.43	6.42
2012	8.31	7.01	7.34	6.19
2013	8.48	6.99	7.28	6.00
2014	8.65	6.96	7.26	5.84
2015	8.82	6.93	7.23	5.68
2016	9.00	6.89	7.41	5.68
2017	9.18	6.86	7.60	5.68
2018	9.37	6.82	7.79	5.68
2019	9.55	6.79	7.99	5.68
2020	9.75	6.75	8.19	5.67

Source: Nominal Values provided by Xcel Energy
Nominal values were converted to 2004 $s by PA for input into Xcel Energy's Strategist model.